Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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October 19, 2009

FILED
2009 OCT 19 P 3:57
PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building, First Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0083 – Hawaiian Electric 2009 Test Year Rate Case
<u>Hawaiian Electric's Responses to Commission Information Requests</u>

Enclosed for filing are Hawaiian Electric Company, Inc.'s ("Hawaiian Electric") responses to the following information requests ("IRs") issued by the Commission to Hawaiian Electric on October 5 and October 12, 2009: PUC IRs 120, 123, 124, 125, 127 to 130, 132 to 136, 138 to 155, 158, 164 to 167, 169, 170, 173, 175, 176, and 183.[1]

Very truly yours,

Enclosures

cc: Division of Consumer Advocacy
Michael L. Brosch, Utilitech, Inc.
Joseph A. Herz, Sawvel & Associates, Inc.
Dr. Kay Davoodi, Department of Defense
James N. McCormick, Department of Defense
Theodore E. Vestal, Department of Defense
Ralph Smith, Larkin & Associates

[1] The IRs issued by the Commission on October 5th and October 12th were numbered as PUC-IR-116 through PUC-IR-183. For reference purposes, Hawaiian Electric has renumbered them as PUC-IR-118 through PUC-IR-185 to follow in sequential order from the IRs previously submitted by the Commission. This was done to avoid confusion with previous IRs which were similarly numbered.

PUC-IR-120

Does HECO anticipate implementing the AMI program, if approved, on the schedule that HECO proposed in Docket No. 2008-0303? If not, will the delay in this program affect (a) the work done by those in the positions referenced in PUC-IR-118, (b) the work done by other HECO employees whose costs are in both included and excluded from interim rates, and (c) the implementation of TOU rates?

HECO Response:

No. Hawaiian Electric will not implement the AMI Project described in the Application in Docket No. 2008-0303 until the Commission has approved the Application. The schedule that Hawaiian Electric proposed in the Application in Docket No. 2008-0303 was based on Commission approval for the AMI Project on or about January 1, 2010. By letter dated August 28, 2009, the Hawaiian Electric Companies requested that the Commission extend the dates of the prehearing conference and evidentiary hearing in the AMI docket. By letter dated September 14, 2009, the Commission granted that request and provided a new procedural schedule.

(a) The delay in the implementation of the AMI Project will not affect the work currently being done by positions 11, 12 and 13 referenced in PUC-IR-118, Attachment 1. All three positions will support the AMI regulatory process in the areas of surcharge development, accounting guidance and revenue requirements development.

(b) As stated in the Companies' August 28, 2009 request to extend the dates of the Commission hearings in Docket No. 2008-0303, "(t)he delay will allow the Hawaiian Electric Companies to provide information on their Smart Grid Roadmaps, and how the proposed AMI will facilitate the roadmaps. The additional time will also allow the Companies to assess the impact, if any, of ongoing developments with respect to their new CIS and Cyber-Security." This will allow Hawaiian Electric to more fully assess and provide additional detail in the areas of CIS integration, Cyber-Security, and Smart Grid interaction with the AMI Project. To complete these wide-ranging tasks, the Hawaiian Electric Companies expect that additional effort will be required by the six AMI positions identified in the Company's response to PUC-IR-119.

(c) The delay in the implementation of the AMI Project should not affect the availability of time of use ("TOU") rate options. TOU rate options for HECO customers were approved in HECO's 2005 test year rate case, Docket No. 04-0113, and were effective as of June 20, 2008. Similar TOU rate options for Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO") are proposed in their respective open rate cases: HELCO's 2006 test year rate case, Docket No. 05-0315 and MECO's 2007 test year rate case, Docket No. 2006-0387. HELCO and MECO will implement TOU rate options upon Commission approval in these rate cases.

Hawaiian Electric has proposed a change in the design of Schedule TOU-R for residential customers in this rate case, and has proposed that that form of Schedule TOU-R be adopted for MECO and HELCO also in the AMI docket. See Exhibit 25 of the AMI application filed December 1, 2008 in Docket No. 2008-0303. MECO has proposed that form of Schedule TOU-R in its 2010 test year rate case filed September 30, 2009 in Docket No. 2009-0163, and HELCO plans to propose that form of Schedule TOU-R in its 2010 test year rate case to be filed in Docket No. 2009-0164.

Also in this rate case, Hawaiian Electric has proposed to limit participation in the proposed Schedule TOU-R to 1,000 residential customers until the new Customer Information System ("CIS") is implemented, which is the same provision in HECO's existing Schedule TOU-R. However, in the AMI docket, Hawaiian Electric proposed to remove meter participation limits. In that docket, Hawaiian Electric indicated that it would make best efforts to accommodate all customers who wish to participate in time-of-use rate options, but proposed to reserve the right to apply to the Commission for meter limitations if and when the Company becomes unable to calculate and deliver bills in a timely manner to customers on time-of-use rate options. See Exhibit 25 to the AMI Application filed December 1, 2008 in Docket No. 2008-0303.

PUC-IR-123

Was the cost of any employee positions specific to the Big Wind Implementation Studies included in interim rates? Were these positions among those excluded from interim rates on pages 12 and 13 of HECO ST-15? If not, please explain why these positions remain in rates.

HECO Response:

There are no employee positions "specific" to the Big Wind Implementation Studies. There are positions, including positions that existed before the 2009 test year (e.g., in System Integration, Project Management, Regulatory Affairs) that have spent a limited portion of their time on work related to the Company's Big Wind Implementation Studies proceeding (Docket No. 2009-0162). These positions include four of the 13 "HCEI positions" that the Company excluded from its revenue requirement in its July 8, 2009 *Revised Schedules Resulting from Interim Decision and Order* and therefore excluded from recovery through interim rates. (See pages 12 and 13 of HECO ST-15.) Attachment 1 of the Company's response to PUC-IR-118 indicates that these four "HCEI positions" (6 through 9) spent 25% of their workload on Big Wind Implementation Studies.

All of the positions that have worked on this project should be recovered through rates, since their work in analyzing and studying the impacts of intermittent renewable energy resources (including solar as well as wind) is critical to Hawaiian Electric's mission of (1) providing adequate and reliable electric service to its customers, and (2) helping Hawaii achieve its energy and environmental policy objectives, as embodied in Act 155 (2009) (Renewable Portfolio Standards and Energy Efficiency Standards) and Act 234 (2007) (Greenhouse Gas Emissions Reductions). In addition, the staff assisting with the Big Wind Studies has worked only a limited portion of their time on this project. Further, the costs of these merit positions are fixed since the Company will incur the same cost of salaries even as these positions work beyond the eight hour work day and on other projects and regardless of whether they work on this project.

In Docket No. 2009-0162, the Company has proposed to recover non-labor outside services (i.e., consulting) costs for the Big Wind Implementation Studies through the REIP/CEI surcharge. This proceeding is in progress and has not yet been ruled on by the Commission. Hawaiian Electric has not proposed to recover labor costs through the surcharge due to the Consumer Advocate's opposition to surcharge recovery of labor costs. See pages 88-90 of Exhibit 1 of the May 15, 2009 Stipulated Settlement Letter in this rate case. Without surcharge recovery, the costs of these positions incurred in the test year should be allowed for recovery through base rates in this rate case. Otherwise, the Company will lose recovery of these costs.

PUC-IR-124

Was the cost of any employee positions specific to the Clean Energy Scenario Process (CESP) included in the interim rates? Were these positions among those excluded from interim rates on pages 12 and 13 of HECO ST-15? If not, please explain why these positions remain in rates.

HECO Response:

As explained in the Rate Case Update, HECO T-15, pages 8-10, the IRP Division was eliminated and all six positions were reassigned to the newly-formed Corporate Planning Department, which consolidated the existing Strategic Initiatives and Integrated Resource Planning ("IRP") functions and added new responsibilities for enterprise risk management ("ERM"). Seven of the eight positions in the department existed prior to the 2009 test year and were reassigned from other areas. A Manager, needed to lead the department, was the position added in the HECO T-15 Update and filled on August 11, 2008.

The Strategic Planning Division of the Corporate Planning Department, which consists of two directors sharing a pool of four analysts and planners, is tasked with performing functions related to strategic planning, IRP/CESP, and ERM. Thus, there are no employee positions "specific" to the CESP process (or the IRP process) in interim rates, but employee positions within the Corporate Planning Department are expected to spend a portion of their time working on CESP (or IRP) and the cost for these positions are included in interim rates. Similarly, many other departments and divisions have been part of the IRP process and are planned to participate and contribute to the CESP process as part of their assignments. Examples include Sales Forecasting, Generation Planning, Transmission Planning, and Power Supply Engineering. The costs for these employee positions are also included in interim rates, but do not have any positions specific to the CESP (or IRP) process.

None of these positions in the Strategic Planning Division are among those excluded from interim rates on pages 12 and 13 of HECO ST-15. These positions should be included in rates because they perform resource planning functions necessary for the provision of electric utility service, whether the output of the planning process is termed a Clean Energy Scenario Plan or an Integrated Resource Plan. As stated above, these positions are expected to spend a portion of their time working on CESP. The costs for work associated with the CESP function itself in the test year should be included in rates because such activity has been authorized by Commission order. Decision and Order No. 11523, filed on March 12, 1992, as amended by Decision and Order No. 11630, filed on May 22, 1992, in Docket No. 6617, established an IRP Framework and required the electric and gas utilities in Hawaii to develop integrated resource plans in accordance with the IRP Framework. On October 20, 2008, the Energy Agreement was executed. Pursuant to the Energy Agreement, Hawaiian Electric and the Consumer Advocate filed a letter on November 6, 2008, requesting the Commission, among other things, to close the IRP-4 proceeding (Docket No. 2007-0084) and to open a new docket to establish the CESP process upon submission of a proposed CESP Framework for the Commission's review and approval. On November 26, 2008, the Commission issued an order closing Docket No. 2007-0084. The order stated: "As the commission is closing this docket to allow for resources to be diverted to development of a CESP framework, the commission directs HECO to suspend all activities pursuant to the IRP Framework." It further stated that "...the commission's preference is that the parties revise the IRP framework to develop their proposed CESP framework." On April 28, 2009, the Hawaiian Electric Companies, Kauai Island Utility Cooperative and the Consumer Advocate filed a proposed revision to the IRP Framework that would constitute a proposed CESP Framework, and requested the Commission to open an investigatory docket to review and establish a CESP Framework. On May 14, 2009, the Commission issued an order in Docket No. 2009-0108 to initiate an investigative proceeding to examine the proposed amendments to the IRP Framework. This proceeding is currently ongoing. In the 2009 test year, the Company's work activity in CESP consists of revising the IRP Framework into the proposed CESP Framework and on participation in this docket. Therefore, the costs associated with the positions that are working on CESP in the test year should be included in rates.

PUC-IR-125

Will the CESP, if approved by the Commission, be conducted by (a) employees from other parts of the company, (b) new employees, or (c) third parties? If HECO plans to utilize employees from other parts of HECO, please describe which divisions they are from and what work will be replaced by CESP activities. If HECO plans to hire new employees, state the expected timing of the hires, the approximate total costs, and the divisions into which they will be hired. If HECO plans to utilize third parties, describe when they will be hired and their approximate costs in each year.

HECO Response:

The proposed CESP Framework is still being investigated in Docket No. 2009-0108, *Instituting a Proceeding to Investigate Proposed Amendments to the Framework for Integrated Resource Planning*. The Stipulated Procedural Order was recently approved on September 23, 2009 and the schedule of proceedings has been extended into the first quarter of 2010.

As explained in its response to CA-IR-333, subpart c, at this time, HECO is not anticipating the proposed CESP process to vary dramatically from the past IRP process in terms of Company resources. It is expected that the departments/divisions that were involved with the IRP process would still be involved with the proposed CESP process such as Corporate Planning Department (including the Strategic Planning Division, which absorbed the responsibilities of the old IRP Division, and the Sales Forecasting Division), Energy Services Department, System Integration Department (Generation Planning Division, Transmission Planning Division), Power Supply Engineering Department, and Resource Acquisition Department (Generation Bidding Division, Renewable Technology Division). However, the proposed CESP process would expand to include activities of two divisions of the Company that were not heavily involved with the past IRP process. The Distribution Planning Division and Renewable Energy Planning Division will be involved with developing the locational value maps and renewable energy zones proposed in the CESP Framework. HECO is also planning to continue to utilize third parties for studies and information that would be used to formulate assumptions for the proposed CESP process, similar to what was done in the past IRP process.

Please see response to PUC-IR-166 for cost information related to IRP/CESP for 2009 and 2010. As stated in the Company's response to CA-IR-333, subpart c, currently, there is still a level of uncertainty on the exact scope of work in the CESP process since we do not have a final Commission decision and order ("D&O") on what the CESP Framework will require. Whether new positions and how much third-party work would be required to execute the new CESP Framework would be re-evaluated after the final Commission D&O in Docket No. 2009-0108.

PUC-IR-127

Without the Power Purchase Adjustment Clause, how does HECO recover the capacity and non-fuel (O&M) components of power purchase agreements? Please include a description of the timing and regulatory lag associated with such collections.

HECO Response:

HECO currently recovers capacity and non-fuel purchased power expenses through base rates (including through an interim rate increase). The Commission must approve the incurrence of such expenses through approval of a purchased power contract. Subsequent to Commission approval of the purchased power contract, cost recovery for capacity and non-fuel purchased power expenses must be approved by the Commission in a general rate case before these costs are included in base rates. It is possible for HECO to incur capacity and non-fuel purchased power expenses subsequent to Commission approval of the purchased power contract, but prior to receiving Commission approval to include such expenses in base rates. Those expenses are not recovered by HECO.

PUC-IR-128

Please provide a table comparing HECO's actual cost recovery for the purchased power capacity and non-fuel (O&M) components of power purchase agreements to what its cost recovery would have been in each year from 2006 to 2008 if it had operated under the proposed Power Purchase Adjustment Clause. Also describe any timing differences in cost recovery between what HECO experienced and what it would have experienced with the proposed Power Purchase Adjustment Clause.

HECO Response:

A table that compares purchased power expenses in approved rates with the estimated recovery of expenses under the proposed Purchased Power Adjustment Clause is provided on page 2 of this response. It is estimated that implementation of the proposed Purchased Power Adjustment Clause would reduce the elapsed time between any increase or decrease in eligible purchased power expenses and their recovery through changes in rates. Absent a Purchase Power Adjustment Clause, rate case test year estimates are made for eligible expenses, and must be approved by the Commission prior to cost recovery.

		Purchased Power Adjustment Clause Estimate (Recorded Expenses, $ Thousands)			Purchased Power Expenses in Approved Rates ($ Thousands)		
		2006	2007	2008	2006	2007	2008
					Note 1	Note 2	Note 3
Kalaeloa	Non-Fuel (O&M)	19,721	20,079	21,161	19,672	19,862	20,814
	Shortfall	0	0	0	0	0	0
	Capacity	32,719	32,719	32,719	32,719	32,719	32,719
	Sub-Total	52,440	52,798	53,880	52,391	52,581	53,533
AES	O&M	26,859	28,165	29,372	26,526	26,868	28,578
	Capacity	65,800	66,772	67,709	67,514	67,577	67,891
	Bonus	1,197	1,157	1,132	1,230	1,217	1,154
	Sub-Total	93,856	96,094	98,213	95,270	95,662	97,623
H-POWER	Capacity	6,972	6,200	6,699	6,901	6,897	6,877
	Total	153,268	155,092	158,792	154,562	155,141	158,033

Notes:

1. Estimate for 2006 based on HECO-R-505 and HECO-R-506 in HECO's 2005 Test Year, Docket No. 04-0113, with a subsequent downward adjustment of $112,000 in Kalaeloa capacity payments, as reflected in HECO's "Final Position Revenue Requirements With Adjustment to Kalaeloa Capacity", Attachment 2, filed on September 19, 2005. The Interim rate increase was implemented on September 28, 2005.
2. Interim rate increase for HECO's 2007 Test Year, Docket No. 2006-0386 was implemented on October 22, 2007. For the purposes of this estimate, 2007 is prorated based on 2006 rates for 10 out of 12 months, and the October 22, 2007 Interim rates for 2 out of 12 months.
3. Estimate for 2008 based on the Interim rate increase for HECO's 2007 Test Year, Docket No. 2006-0386, Implemented on October 22, 2007.

PUC-IR-129

Please describe how the proposed Power Purchase Adjustment Clause would affect the results of a lead-lag study.

HECO Response:

The proposed Power Purchase Adjustment Clause would not affect the results of a lead-lag study. As described in HECO T-18, working cash is comprised of the net of the revenue collection lag and the payment lags. The revenue collection lag is the time between the provision of electric service and the receipt of cash for that service. In addition, as described by Mr. Darren Yamamoto in HECO T-9, the test year estimate of revenue lag days was calculated by adding a fixed number of days (representing the mid-point of the monthly bill) to a variable number that represents the average amount of time it takes to bill a customer and receive payment for the bill. As described in HECO T-18, a payment lag occurs when the Company incurs an obligation to pay for an item or service before the Company actually pays for it. In essence, the payment lag is measured from the point in time in which the Company incurs an obligation to pay for an item or service (when the item is received or the service provided) to the point when the payment of this obligation is made (and clears the bank).

The proposed Power Purchase Adjustment Clause, as described by Mr. Peter Young in Rate Case Update, HECO T-22, effectively shifts the recovery of certain purchased power costs from base rates to the new clause. The amount of revenues received by the Company under the proposed Power Purchase Adjustment Clause would not be different from the amount of revenues received under base rates. This proposal does not impact the total revenues received or the purchased power expenses recorded. The assumptions utilized in the calculation of the revenue lag days (the mid-point of the monthly bill and the average amount of time it takes to bill a customer and receive payment for the bill) would remain unchanged. Therefore, the revenue lag days, which represents the time between the provision of electric service and the receipt of cash for that service, would remain unchanged. Given that revenues would not change under this proposal, the revenue collection lag would not change either.

Implementation of the proposed Power Purchase Adjustment Clause would also have no affect on the payment lag, as it represents a mechanism by which the Company will recover its purchased power expenses. The Company is not changing any purchased power expenses in the test year revenue requirement. As the payment lag captures the time between the point in time in which the Company incurs an obligation to pay for a service, to the point when the payment of this obligation is made, the proposed Power Purchase Adjustment Clause would not have any impact on the payment lag days for purchased power expense.

PUC-IR-130

How, if at all, did the proposed Settlement Agreement's cash-working capital calculations consider the Power Purchase Adjustment Clause?

HECO Response:

The proposed Power Purchase Adjustment Clause did not affect the cash-working capital calculation. If approved, the recovery of purchased power costs would be transferred from base rates to the new clause and have no impact on the amount of revenue collected. The proposed Power Purchase Adjustment Clause also does not impact the purchased power expense included in the test year revenue requirement. As such, since revenues and purchased power expenses are not impacted by the proposed Power Purchase Adjustment Clause, there is no impact to the cash-working capital calculation. Please see the Company's response to CA-IR-129 for further discussion.

PUC-IR-132

Under the current ECAC, through what process could HECO engage in fuel hedging?

<u>HECO Response:</u>

The ECAC is designed, consistent with the general practices of other fuel adjustment clauses for electric utilities, to pass through to customers HECO's prudent purchased fuel and energy costs as Dr. Makholm explains on pages 4 through 8 of HECO ST-10B. Hedging the cost of purchased commodity inputs, such as generator fuel and purchased power – that is, stabilizing the price of those commodities by paying counterparties to bear the risk of price changes – could be included in the ECAC if that is a policy adopted by the Commission.

With respect to the "process" of including fuel hedging in the ECAC, there are two considerations; one relating to the creation of a Commission-mandated hedging program, and the other for the operational implementation of that program.

With respect to a Commission-mandate program, if there were to be one, the Commission, HECO and other stakeholders should collaborate and agree on what level of fuel cost hedging is in ratepayers' interest – since ratepayers will bear the cost, with those costs to be flowed through under the ECAC. The quantitative parameters of the hedge program (i.e., what should be hedged, in what percentages vis-à-vis the projected fuel purchases, and what types of instruments should be used to do so) would have to be specified in advance, *ex ante*, in order for the program to objectively satisfy the plan's requirements. The advance agreement on such a plan, the *ex ante* objectivity of its goals to shield ratepayers from some elements of price volatility, and the implementation of a customer education campaign to explain the implications of a hedge program on customer bills is crucial if the hedging program is to proceed in an orderly fashion without *ex post* conflict over whether the plan was a prudent one. That is, the basis for any such hedging program is not to time the market but to shield ratepayers from volatility for a fee. Such a program can only usefully be assessed *ex ante*, not *ex post* on the basis of whether the general level of prices rose or fell.

The second consideration in a "process" for fuel hedging is an *ex post* review whether the Company faithfully carried out the agreed mandate to acquire hedge instruments from the market at the agreed times, in the agreed quantities, and through reasonable interaction with counterparties in the commodity and financial markets. That is, this second part of the process merely validates that the Company has carried out the plan as specified. As far as the cost of the plan, as Dr. Makholm explain on page 19 of HECO ST-10B, to the extent that a fuel price hedging program were mandated by the Commission, acting on behalf of ratepayers, then "recovery of the hedging and risk premium costs associated with physical and financial hedges would necessarily have to be included in the ECAC."

PUC-IR-133

Does HECO currently have any long-term, fixed-price fuel contracts? If so, please describe their (a) size in terms of fuel quantity, (b) duration, (c) counterparty, (d) approval process, and (e) cost recovery process.

HECO Response:

No. HECO currently does not have any long-term, fixed-priced fuel contracts.

PUC-IR-134

Please describe how any of the new mechanisms proposed by HECO in this rate case (such as the Power Purchase Adjustment Clause) or outside of this rate case (such as decoupling and the Revenue Adjustment Mechanism) facilitate or inhibit fuel hedging.

HECO Response:

The power purchase adjustment clause ("PPAC") neither facilitates nor inhibits fuel hedging. The PPAC is an expense recovery mechanism that recovers purchased power costs not recovered through the energy cost adjustment clause. Fuel hedging is a financial arrangement that mitigates fuel price risk through forward contracts. Since the PPAC recovers purchased power costs, while fuel hedging is a risk mitigating mechanism for fuel oil acquisition at pre-determined prices, the PPAC operates completely independently of fuel hedging.

Sales decoupling and the revenue adjustment mechanism ("RAM") also do not facilitate nor inhibit fuel hedging. Sales decoupling is proposed by the HECO Companies[1] and the Consumer Advocate in Docket No. 2008-0274 to be implemented through a revenue balancing account ("RBA") that accumulates the difference between recorded adjusted revenue and a target revenue approved by the Commission.[2] Recorded adjusted revenues exclude actual fuel and purchased power costs recovered through base rates and the energy cost adjustment and purchased power adjustment clauses. Target revenues also exclude test year fuel and purchased power costs. Therefore, regardless of whether actual fuel costs are the result of market purchases of fuel or financial hedging, those costs are removed from the RBA such that sales decoupling only compares revenue that recovers fixed costs. Therefore, sales decoupling neither facilitates or inhibits fuel hedging.

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[1] HECO Companies are Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc., and Maui Electric Company, Ltd.

[2] See the HECO Companies and Consumer Advocate's Final Statement of Position, filed May 11, 2009, in Docket No. 2008-0274, Exhibit A.

The RAM also excludes fuel and purchased power costs; therefore, it neither facilitates nor inhibits fuel hedging.[3]

[3] See the HECO Companies and Consumer Advocate's Final Statement of Position, filed May 11, 2009, in Docket No. 2008-0174, Exhibit B.

PUC-IR-135

According to page 17 of HECO-ST-10(8), "If a utility offering a fixed rate or flat bill program did not hedge against this fixed price obligation, they would be effectively speculating on the fuel markets."

Is HECO willing or able to engage in fixed-rate billing without some form of physical of financial hedging? If so, is such hedging possible under the current ECAC?

HECO Response:

HECO is not willing nor able to engage in fixed-rate billing without some form of hedging. The point of the ECAC, and indeed the point of fuel and gas adjustment clauses generally, is to free utilities from what otherwise would be the burden of securing from the market the commodity inputs needed to serve ratepayers where those fuel prices are inherently unpredictable. The ECAC performs this function usefully while at the same time providing the heat rate efficiency factors described in Dr. Makholm's testimony on pages 8 and 9, HECO ST-10B.

The Company supports the ECAC and believes it to serve a useful purpose, as described by Dr. Makholm throughout his testimony, HECO ST-10B. Allowing some customers a fixed rate option would confront the Company with a situation for which the market for fuels and power exacts a price -- the premium for accepting and absorbing the risk of future price volatility. To the extent that question postulates that the Company would shift this risk to ratepayers not choosing such a fixed-rate option, the burden of such a premium in the market would unfairly fall on these other ratepayers. The issue of whether the Company could absorb such risk without compensation, Dr. Makholm answers no. That risk must be borne – it does not go away simply because of the transfer from ratepayers opting to participate in a fixed-rate billing program to the Company.

The ECAC contemplates the pass through of all fuel and purchased power costs to ratepayers – allowing for the heat rate efficiency factor. The ECAC, as proposed, contemplates to fixed bill programs or deviations from a full fuel and purchased power cost pass through. Therefore, under the current ECAC, the Company is neither able nor willing to provide to ratepayers a fixed-rate billing option without the ability to hedge to pay the market price for taking that risk away from ratepayers.

PUC-IR-136

How does HECO anticipate that inclining block rates will affect (a) average and (b) aggregate residential customer electricity consumption? Does HECO anticipate that changes in customer behavior will take place immediately or over a longer time period? Please provide all analysis used in estimating customer responses to the introduction of inclining block rates. Provide any estimates of short-term and long-term price elasticity of demand for different customer classes.

HECO Response:

HECO has not estimated or attempted to quantify the impacts to customer electricity consumption as a response to the proposed introduction of inclining block rates for the residential rate class (HECO has also proposed inclining block rates for the residential rate class in the HECO 2007 test year rate case, Docket No. 2006-0386). See also the response to PUC-IR-137.

PUC-IR-138

According to Attachment 2 of HECO's response to PUC-IR-104, under the proposed Schedule R, the energy charge for the first 350 kWh consumed each month is $26.2113 per kWh, followed by $27.3648 per kWh for the next 850 kWh and $28.4968 per kWh for consumption in excess of 1200 kWh. Please provide all analysis that HECO conducted indicating that for the proposed TOU-R the usage charge (inclining block rates) should increase by $1.1535 for consumption in excess of 350 kW and an additional $1.132 for consumption in excess of 1200 kWh.

HECO Response:

This response assumes that the request refers to the proposed Schedule R and the proposed rates for the non-fuel energy charge tiers. The guidelines used to determine the non-fuel energy charges for the kWh tiers were to target an increase for customers whose billing quantities fell into the first tier (which is proposed to be capped at 350 kWh per month) that is less than the 5.2% increase assigned to the class at current effective rates. The Schedule R rate design also targeted no more than approximately the class average increase, 5.2%, for customers whose billing quantities fall into the upper levels of the second tier (which is proposed to be capped at 1,200 kWh per month). See HECO T-22, page 27, lines 18-25. The proposed rate differences for the non-fuel energy charge tiers were set in order to satisfy these rate design guidelines. A spreadsheet that shows bill calculations at current effective and proposed rates is included with this response as Attachment A.

PROPOSED RATES

HAWAIIAN ELECTRIC COMPANY, INC.
Docket No. 2008-0083, Test-Year 2009
SCHEDULE R - RESIDENTIAL SERVICE

			Interim
	9.00	$/mo	7.12%
	18.00	$/mo	
		cents/kwh	
	10.0480		
1.1535	11.2015		
1.132	12.3335		
	16.1633	cents/kwh	
	26.2113	cents/kwh	
	17.00	$/mo	
	23.00	$/mo	
	0.0		
	10.50	$/mo	
	18.50	$/mo	
	31.2113	cents/kwh	
	28.2113	cents/kwh	
	22.7113	cents/kwh	
	18.50	$/mo	
	23.50	$/mo	
	5.00	$/unit/mo	
	10.0	%	
	(660.1)	$000s	
	0.000	¢/KWH	
	0.000	(%)	
	0.000	(%)	
	0.0000	¢/KWH	
	590,002.7		
	590,002.7		

	0.0		

	% Increase	(Base+Non-Fuel)*(1+Interim)+ECAC
350	2.2500%	25.6345
1200	6.7500%	
	11.1658%	

Bill Impact - Single Phase

	Current Effective Rates (Incl. Interim)			Proposed Rates			
kWh	Base	Adjustments	Total	Base	Adjustments	Total	% Increase
0	$16.00	$1.14	$17.14	$17.00	$0.00	$17.00	-0.8%
100	$25.19	$9.01	$34.20	$35.21	$0.00	$35.21	3.0%
200	$42.38	$17.46	$59.84	$61.42	$0.00	$61.42	2.6%
300	$59.57	$25.90	$85.47	$87.63	$0.00	$87.63	2.5%
350	$68.16	$30.12	$98.28	$100.74	$0.00	$100.74	2.5%
400	$76.76	$34.35	$111.11	$114.42	$0.00	$114.42	3.0%
500	$93.95	$42.80	$136.75	$141.79	$0.00	$141.79	3.7%
600	$111.14	$51.24	$162.38	$169.15	$0.00	$169.15	4.2%
700	$128.33	$59.69	$188.02	$196.52	$0.00	$196.52	4.5%
800	$145.52	$68.13	$213.65	$223.88	$0.00	$223.88	4.8%
900	$162.71	$76.57	$239.28	$251.25	$0.00	$251.25	5.0%
1,000	$179.90	$85.02	$264.92	$278.61	$0.00	$278.61	5.2%
1,100	$197.09	$93.46	$290.55	$305.98	$0.00	$305.98	5.3%
1,200	$214.28	$101.91	$316.19	$333.34	$0.00	$333.34	5.4%
1,300	$231.46	$110.35	$341.81	$361.84	$0.00	$361.84	5.9%
1,400	$248.65	$118.79	$367.44	$390.33	$0.00	$390.33	6.2%
1,500	$265.84	$127.25	$393.09	$418.83	$0.00	$418.83	6.5%
1,600	$283.03	$135.69	$418.72	$447.33	$0.00	$447.33	6.8%
1,700	$300.22	$144.14	$444.36	$475.82	$0.00	$475.82	7.1%
1,800	$317.41	$152.58	$469.99	$504.32	$0.00	$504.32	7.3%
1,900	$334.60	$161.02	$495.62	$532.82	$0.00	$532.82	7.5%
2,000	$351.79	$169.47	$521.26	$561.31	$0.00	$561.31	7.7%
2,100	$368.98	$177.91	$546.89	$589.81	$0.00	$589.81	7.8%
2,200	$386.17	$186.36	$572.53	$618.31	$0.00	$618.31	8.0%
2,300	$403.36	$194.80	$598.16	$646.81	$0.00	$646.81	8.1%
2,400	$420.55	$203.24	$623.79	$675.30	$0.00	$675.30	8.3%
2,500	$437.74	$211.70	$649.44	$703.80	$0.00	$703.80	8.4%
3,000	$523.69	$253.92	$777.61	$846.28	$0.00	$846.28	8.8%
5,000	$867.48	$422.81	$1,290.29	$1,416.22	$0.00	$1,416.22	9.8%
10,000	$1,726.96	$845.06	$2,572.02	$2,841.06	$0.00	$2,841.06	10.5%
20,000	$3,445.92	$1,689.55	$5,135.47	$5,690.74	$0.00	$5,690.74	10.8%
25,000	$4,305.40	$2,111.79	$6,417.19	$7,115.58	$0.00	$7,115.58	10.9%
100,000	$17,197.60	$8,445.47	$25,643.07	$28,488.18	$0.00	$28,488.18	11.1%

PUC-IR-139

According to Attachment 2 of HECO's response to PUC-IR-104, under proposed Schedule R, the energy charge for the first 350 kWh is $26.2113 per kWh, followed by $27.3648 per kWh for the next 850 kWh and $28.4968 per kWh for consumption in excess of 1200 kWh. Did HECO consider proposing larger percentage increases in rates between tiers of inclining block rates? If so, please describe why steeper rate increases in rates as consumption increases would be inappropriate for HECO's Schedule R customers.

HECO Response:

HECO did not consider proposing larger percentage increases in rates between tiers of inclining block rates. Inclining block rates for Schedule R were first proposed in HECO's 2007 test year rate case, Docket No. 2006-0386, which is pending before the Commission. In that case, the proposed difference between the lowest block tier and the middle block tier was 1.2970 cents per kWh, and the proposed difference between the middle block tier and the highest block tier was 0.8927 cents per kWh (see HECO-106, page 5, in Docket No. 2006-0386). The proposed rate design for Schedule R in this case attempted to keep about the same cents per kWh difference between blocks, approximately one cent per kWh, subject to the rate design guidelines, as described in HECO's response to PUC-IR-138.

PUC-IR-140

The Commission observes that the percentage increase for the energy component of rates between the highest and lowest rate tiers for inclining block rates in certain other jurisdictions is much larger than that proposed by HECO, whose proposed Schedule R rates appear to increase less than 9% from the lowest tier to the highest tier. See Southern California Edison at http://www.sce.com/NR/sc3/tm2/pdf/ce12-12.pdf, and Puget Sound Energy at http://www.pse.com/SiteCollectionDocuments/rates/elec_sch_007.pdf. Does HECO believe that its proposed rate increases are sufficient to affect customer behavior? If so, please provide all analysis that HECO has conducted to determine how much customers will likely change their behavior.

HECO Response:

HECO does not know if the differences in inclining block rates in the proposed Schedule R are sufficient to affect customer behavior. HECO has not conducted any analysis to determine how much customers will change their behavior. As discussed in HECO's 2007 test year rate case, the merits of an inclining block rate design include the mitigation of rate impact on the smallest users of the system, and the assignment of a greater share of the cost increase to the larger users, in addition to the establishment of pricing signals that encourage conservation (HECO T-20, page 19, Docket No. 2006-0386).

PUC-IR-141

According to Attachment 2 of HECO's response to PUC-IR-104, the usage charge in Schedule TOU-R is $1.00 for consumption greater than 350 kWh and $2.00 for consumption greater than 1,200 kWh. Please provide all analysis that HECO conducted indicating that for the proposed TOU-R the usage charge (inclining block rates) should be $1.00 for consumption in excess of 350 kW and $2.00 for consumption in excess of 1,200 kWh.

HECO Response:

The proposed usage charge in Schedule TOU-R of 1.0 ¢ per kWhr for all kWhr between 350 kWh and 1,200 kWh per month and 2.0 ¢ per kWhr for all kWhr over 1,200 kWhr per month is intended to approximate (rounded to the nearest cent) the proposed difference between the rates in the non-fuel energy charge usage tiers in the proposed Schedule R.

PUC-IR-142

According to Attachment 2 of HECO's response to PUC-IR-104, the usage charge in Schedule TOU-R is $1.00 for consumption greater than 350 kWh and $2.00 for consumption greater than 1,200 kWh. Did HECO consider having larger percent increases in rates between tiers of inclining block rates? If so, please describe why steeper increases in rate as consumption increases would be inappropriate for Schedule TOU-R customers.

HECO Response:

No, HECO did not consider having larger percent increases in rates between tiers of inclining block rates. See HECO's response to PUC-IR-141.

PUC-IR-143

Please provide a narrative explanation and all documentation and analysis of why 350 kWh and 1,200 kWh are the appropriate tier cutoffs for inclining block rates.

<u>HECO Response:</u>

The proposed Schedule R non-fuel energy inclining block kWh usage tiers, were first proposed in the HELCO 2006 test year rate case, and were subsequently proposed in the HECO 2007 test year rate case, in the MECO 2007 test year rate case, and again in the HECO 2009 test year rate case. The first tier kWh level was set to provide the lowest energy rate for a base kWh usage level. The first tier was set to include about one-quarter of all residential customer bills and about one-half of all residential kWh. The second tier kWh level was set to capture the majority of the kWh. The second tier was set such that about 90% of all residential kWh would be billed at either the first or second tier rate; only the very highest residential customer usage would be billed at the highest, third tier rate.

PUC-IR-144

What percentage of HECO residential customers' average monthly electricity consumption (a) falls below 350 kWh or (b) exceeds 1,200 kWh?

HECO Response:

Based on the billing data used to estimate revenues in this case, about 46.3% of HECO residential customer monthly kWh is equal to or less than 350 kWh, and about 9.5% of monthly residential kWh exceeds 1,200 kWh.

PUC-IR-145

In designing rates, how many customers did HECO anticipate would participate in Schedule TOU-R? Please provide all documentation and analysis supporting these estimates.

HECO Response:

HECO did not make an estimate of how many customers would participate in Schedule TOU-R.

See also HECO's response to PUC-IR-150.

PUC-IR-146

What percentage of customers eligible for TOU-R rates elected to use those rates in 2008? How many customers used Schedule TOU-R rates in 2008? Please describe any program-size or geographical limits on participation in Schedule TOU-R rates in 2008, as well as how those limits affected participation. Will any such limits persist in the test year?

HECO Response:

There were two customers on Schedule TOU-R in 2008, and there are currently seven customers on the rate. The existing Schedule TOU-R is limited to 1,000 residential customers until the new Customer Information System is implemented. The same participation limit consideration was proposed in the HECO 2009 test year rate case which was filed in July 2008. Meter limits on participation were proposed in order to manage HECO's ability to deliver timely bills for time-of-use rate option customers since all of those bills must be calculated and processed manually. In the HECO Companies' AMI application, Docket No. 2008-0303, filed in December 2008, the HECO Companies proposed to remove meter limits previously proposed. The HECO Companies stated that they will make their best efforts to accommodate all customers who wish to participate in time-of-use rate options, but the HECO Companies also propose to reserve the right to apply to the Commission for meter limitations if and when the HECO Companies become unable to calculate and deliver bills in a timely manner to customers on time-of-use rate options (see Docket No. 2008-0303, Exhibit 25).

PUC-IR-147

What percentage of customers eligible for Schedule TOU-C rates elected to use those rates in 2008? How many customers used Schedule TOU-C rates in 2008? Please describe any size or geographical limits on participation in Schedule TOU-R rates in 2008, as well as how those limits affected participation. Will any such limits persist in the test year?

HECO Response:

There is one customer on Schedule TOU-C, and this customer began service on this rate option in 2008. There are no limits on participation in Schedule TOU-C rates.

PUC-IR-148

Please provide any analysis that HECO conducted on the change in participation for TOU-R rates based on reducing the number of periods under the rates from three to two.

HECO Response:

HECO has not conducted any analysis on the change in participation in Schedule TOU-R rates based on reducing the number of periods under the rates from three to two.

PUC-IR-149

Please compare both average monthly kWh consumption and average monthly bills for customers who participated in Schedule TOU-R rates in 2008 and customers who did not.

<u>HECO Response:</u>

There were only three monthly bills rendered on Schedule TOU-R in 2008. The average kWh for these three bills was 2,726 kWh (327 kWh priority peak, 775 kWh mid-peak, and 1,624 kWh off-peak) for an average base bill of $453.10, based on the Schedule TOU-R base rates only shown in HECO-105, page 85. The average residential customer in 2008 used 654 kWh. The bill for 654 kWh is $120.42, based on the Schedule R base rates only, shown in HECO-105, page 8.

PUC-IR-150

According to Attachment 2 of HECO's response to PUC-IR-104:

> "In total and on average, Schedule R customers who move to Schedule TOU-R will have higher bills on Schedule TOU-R than on Schedule R, as shown in columns E and H. In order for customers to realize bill savings on Schedule TOU-R, they must modify their electricity consumption, for example, by shifting loads from on-peak to off-peak hours."

In designing rates and estimating total billing determinates, did HECO estimate that customers would, on average, modify the size and timing of their electricity consumption to enjoy savings from TOU rates? If so, how does HECO predict that customers will modify their behavior? Please provide any such analysis that HECO has conducted. If HECO did not estimate any change in behavior for Schedule TOU-R customers, please explain why such an analysis is inappropriate or unnecessary.

HECO Response:

HECO did not make any estimates or assumptions for modifications of electricity consumption for Schedule TOU-R customers. HECO's revenue estimates at proposed rates do not assume any Schedule TOU-R customers. It is HECO's practice not to estimate new participation in optional rates for rate design purposes, but to only include existing optional rate customers in the test year rate design (HECO's optional rates include the proposed Schedule TOU-R, proposed Schedule TOU-G, proposed Schedule TOU-J, and the existing Schedule U, Rider T, Rider M, and Rider I). For rate design purposes, HECO estimates the revenue savings expected from existing optional rate customers and adds that to the revenue requirement that must collected from all customers in the rate class. In effect, revenue reductions from existing optional rate customers raise the proposed rate levels for all customers in the rate class (including the customers on optional rates). At proposed rates, HECO takes a conservative approach, choosing not to estimate potential savings from new optional rate customers, in order to avoid the risk of proposing higher rates to cover savings from new optional rate customers that do not actually emerge in the test year.

PUC-IR-151

Under HECO's proposed TOU-rates, how many kWh would a customer with the average residential load profile have to move from peak to off-peak periods to break even financially compared to using conventional Schedule R rates?

HECO Response:

The average residential customer in 2008 used 654 kWh. From our 2003 class load study data, based on the proposed TOU-R usage periods, about 26.6% of the residential kWh is used during the proposed on-peak hours and about 73.4% of the residential kWh is used during the proposed off-peak hours. A residential customer who uses 654 kWh that is distributed 26.6% on-peak and 73.4% off-peak, based on the proposed Schedule TOU-R hours, would have to move 55 kWh from on-peak hours to off-peak hours to break even compared to billing on Schedule R rates. This analysis assumes that the Schedule R and Schedule TOU-R rates are as proposed in direct testimony, see HECO-106, pages 7 and 78.

PUC-IR-152

Does HECO anticipate that the elimination of three-step Schedule P and Schedule J declining block rates will affect customer behavior? If so, please describe how such assumptions were included in HECO's projections of energy consumption. Provide all supporting documentation and analysis.

HECO Response:

HECO does not know how the proposed elimination of the Schedule P and Schedule J energy rate load factor blocks will affect customer behavior. HECO did not make any assumptions in its projections of Schedule P and Schedule J energy consumption. See also HECO's response to PUC-IR-137.

PUC-IR-153

Please reconcile the following statements:

Page 103 of HECO-T-7:

> "The rising cost of commodities and transportation continues to increase the price paid for materials purchased by HECO. While price increases are dependent upon many factors such as the quantity of a specific commodity in a product and other non-material costs in the product, suppliers are passing on their higher costs for raw materials through increased prices to HECO. In HECO-746, a sampling of 50 items purchased by PSO&M is shown, including boiler tubes, electronic components, turbine material, and generator material. The average price increase for the items in this sampling was 34.5% for the three year period 2004 to 2007. The average price increase from 2006 to 2007 was 8.1 %."

Page 23 of HECO ST-7: "The change in commodity prices does not correlate with the Production Maintenance expense for materials."

Is HECO arguing that there is no meaningful causal relationship between commodity prices and Production Maintenance expense for materials?

HECO Response:

When the prices of commodities and transportation increase, such increases do place upward pressure on the prices paid for materials that HECO utilizes for Production Maintenance. In HECO-746 of Mr. Giovanni's HECO T-7 direct testimony (which was updated in the Company's response to CA-IR-310), information was presented and discussed to support the long-term upward direction in the prices of commodities and fabricated materials. In Mr. Giovanni's supplemental testimony (HECO ST-7) and accompanying exhibit (HECO S-704), information was presented and discussed that pertained to the short-term volatility of commodity prices and the absence of a correlation with such Production Maintenance material pricing volatility in the test year.

As shown in Attachment 1 to this response, commodity prices and related indices have been extremely volatile the past few years, and peaked in mid-2008. Production Maintenance expenses do not correlate with the month-to-month volatility in commodity prices, and as stated in HECO ST-7, page 24: "The price indices served only as a general point of reference when estimated Production Materials, i.e., changes in the indices were not used directly in computing estimated Production Materials expenses."

In general, in any given year Production Maintenance expenses are managed to a total combined expense for direct and indirect labor, outside services, and materials. If actual materials expenses are higher than budgeted for the given year (which has been the case in recent years, as shown in HECO ST-7, page 23), it is generally compensated for by reduced labor expenses, reduced outside services expenses, reduced maintenance work being performed, or a combination thereof. Conversely, if Production Maintenance materials expense are lower than budgeted as the year unfolds, it would generally result in the opportunity to perform more maintenance work (e.g., from the backlog of maintenance work orders) without exceeding the total maintenance budget for the year.

Hawaiian Electric Company, Inc.
2009 Rate Case
Major Raw Materials Price Indexes

	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07
Consumer Price Index (CPI-U)	198.4	197.0	196.8	197.2	197.6	198.5	200.6	202.1	203.7	203.9	203.7	203.2	203.9	204.3
Copper and Brass Mill Shapes	421.0	415.9	402.6	402.0	379.2	365.0	366.1	431.0	447.3	438.3	448.9	423.0	410.2	426.0
Steel Mill Products	185.3	187.3	180.0	179.0	175.8	178.0	181.7	188.3	190.3	190.5	189.4	183.4	180.2	177.7
Iron and Steel Mills	174.5	176.5	167.9	167.5	163.5	166.5	170.3	177.8	181.0	181.2	180.2	172.1	168.3	165.1
Cement and Concrete Product Manuf	128.1	127.9	128.4	128.6	130.4	130.6	131.2	131.7	131.8	131.8	132.1	132.1	132.3	132.4
Fuels and Related Products and Powei	163.8	148.5	158.4	161.8	152.4	160.2	167.9	174.7	181.3	182.4	186.7	176.3	178.9	180.9

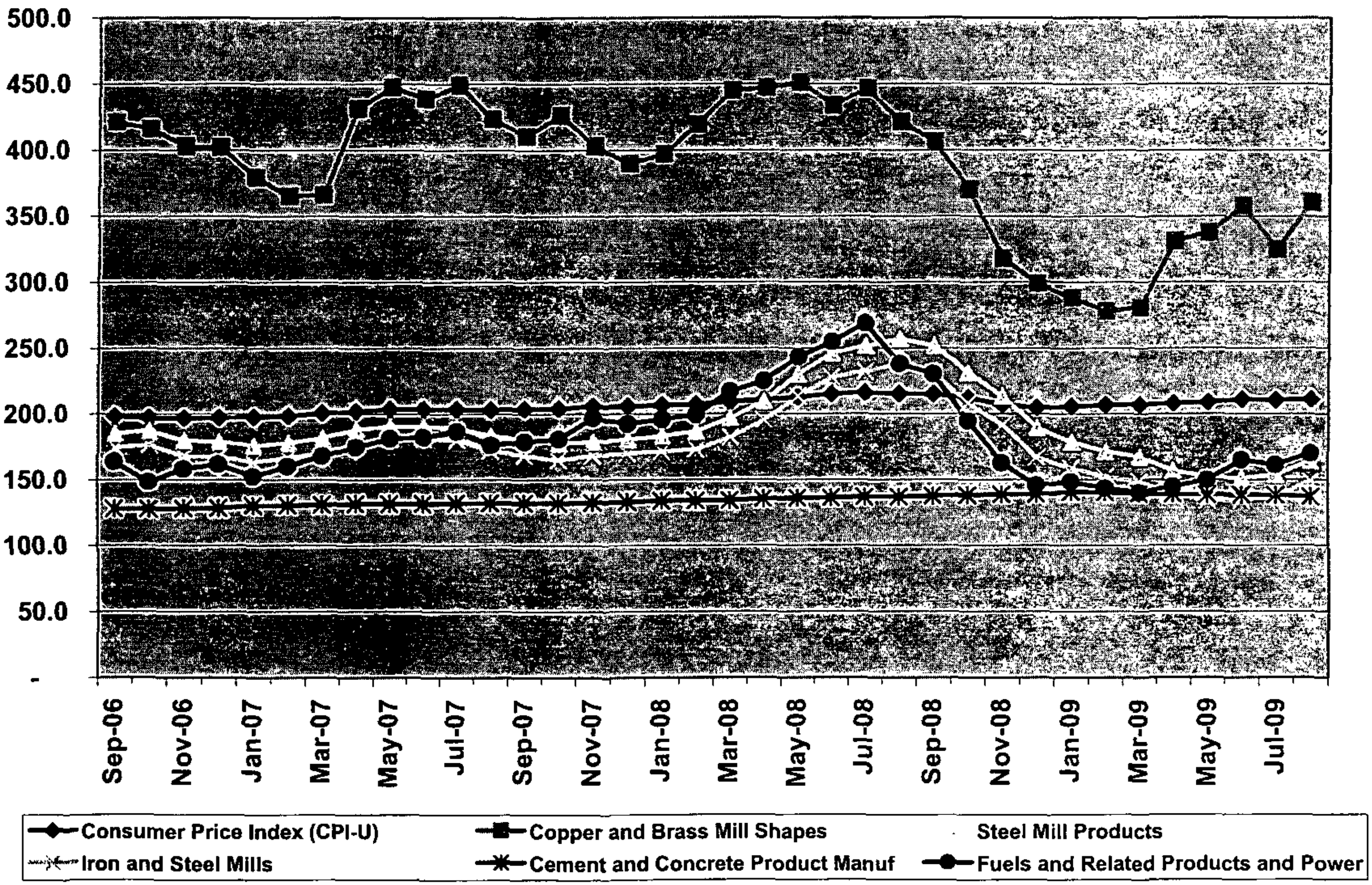
	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08
Consumer Price Index (CPI-U)	205.9	205.8	206.7	207.3	209.1	210.7	212.8	215.2	216.3	215.2	214.9	212.2	207.3	204.8
Copper and Brass Mill Shapes	402.9	389.8	396.9	419.1	444.6	447.0	450.9	433.5	446.6	421.2	405.6	370.0	318.1	298.9
Steel Mill Products	179.0	180.6	183.2	186.6	196.9	209.7	229.9	246.0	251.8	257.0	251.8	231.4	213.6	189.3
Iron and Steel Mills	168.4	169.9	171.5	173.1	182.1	194.9	213.5	227.5	232.3	237.6	231.2	208.3	191.3	167.0
Cement and Concrete Product Manuf	132.8	133.2	133.9	134.0	134.3	135.4	136.0	136.2	136.9	136.9	137.6	138.3	138.6	138.8
Fuels and Related Products and Powei	196.9	192.6	195.9	199.5	217.1	224.7	243.2	254.8	268.7	237.9	230.2	194.5	162.6	145.7

	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Std Dev	Avg	Avg 2009
Consumer Price Index (CPI-U)	205.7	206.7	207.2	207.9	208.8	211.0	210.5	211.2		5.5	206.2	208.6
Copper and Brass Mill Shapes	288.1	277.8	280.7	331.1	337.6	357.7	324.7	360.7		52.2	388.3	319.8
Steel Mill Products	178.8	171.5	167.3	157.0	152.3	151.2	153.8	164.3		28.1	190.8	162.0
Iron and Steel Mills	159.1	152.3	148.4	138.3	133.9	134.3	137.5	148.8		26.9	175.9	144.1
Cement and Concrete Product Manuf	140.7	140.2	139.3	138.9	138.5	138.5	138.1	137.1		3.7	134.5	138.9
Fuels and Related Products and Powei	148.5	143.6	140.2	144.8	149.6	165.1	161.3	170.0		33.6	182.3	152.9
	(P) = Preliminary				(P)	(P)	(P)	(P)	(P)			

Source: U.S. Department of Labor - Bureau of Labor Statistics - Consumer Price Index & Series Report.
May 2009 - August 2009 is preliminary - All indexes are subject to revision four months after original publication.
(data extracted on 09/29/09)

Major Raw Materials Price Indexes

Sept 2006 - Aug 2009



Source: U.S. Department of Labor - Bureau of Labor Statistics - Consumer Price Index & Series Report.
May 2009 - August 2009 is preliminary - All indexes are subject to revision four months after original publication.
(data extracted on 09/29/09)

PUC-IR-153
DOCKET NO. 2008-0083
ATTACHMENT 1
PAGE 2 OF 2

PUC-IR-154

Has HECO to date dispatched the CT-1 unit to provide electricity or ancillary services to the grid? If so, please describe the date of any such dispatches. Please make the distinction between dispatch for testing and dispatch for commercial purposes.

HECO Response:

Since July 31, 2009 Hawaiian Electric has periodically dispatched the CIP CT-1 unit to perform various tests and commissioning activities that require the unit to be tied to the electric utility grid and run at various loads. The following table lists the dates and times the CIP CT-1 unit was dispatched for testing purposes and a brief description of the testing or commissioning activities that were performed. When CIP CT-1 was run for testing and commissioning activities, although it was not the purpose of the run, the unit did provide electricity to the HECO grid.

CIP CT-1 Dispatches for Testing and Commissioning

Date	Time Spans of CT Operation (approx.)	MWH Produced	Description of Testing or Commissioning Activity
7/31/09	13:29-14:25 17:34-19:52	105	Initial synchronization to the grid. Unit started and brought to 25MW without water injection for start of emissions tuning. Unit started and brought to 57MW without water injection as a continuation of emissions tuning.
8/1//09	10:36-18:03	602	Emissions Tuning at various loads. Automatic Voltage Regulator Testing at baseload for approximately 3.5 hours.
8/2/09	10:01-14:47	349	Emissions Tuning completed at various loads.
8/12//09	15:59-18:10	71	Collection of bearing vibration data for turbine balancing at baseload.
8/13/09	11:44-18:44	612	Performance Testing: Baseload Output and Heat Rate
8/18/09	07:14-16:30 17:09-17:47	978	Performance Testing: Evaporative Cooling & Wet Compression (unsuccessful) Overspeed Trip Test (unsuccessful)

CIP CT-1 Dispatches for Testing and Commissioning			
Date	**Time Spans of CT Operation (approx.)**	**MWH Produced**	**Description of Testing or Commissioning Activity**
8/20/09	15:19-20:15	517	Performance Testing: Evaporative Cooling (successful) & Wet Compression (unsuccessful)
8/24/09	15:02-20:59	642	Performance Testing: Wet Compression (successful) Collection of bearing vibration data
8/25/09	10:56-14:37	146	EMS Testing
8/26/09	14:23-17:54	138	EMS Testing
8/28/09	07:29-12:15	525	Collection of bearing vibration data. Unit tripped from full load – suspected inadvertent opening of BOP DCS power supply breaker.
8/31/09	09:07-09:23 16:24-17:31	57	Collection of bearing vibration data – unsuccessful due to water injection problems (ARC valve). Also had diesel oil leak from tubing.
9/3/09	06:40-07:08 10:27-11:46	128	Collection of bearing vibration data – unsuccessful due to combustor air leak in #5 can.
9/5/09	06:32-14:25 14:59-18:54	1,301	Collection of bearing vibration data – successful. ~7 hours at baseload and 3 hours at baseload after hot start.
9/21/09	07:21-07:41 09:01-23:05 23:43-24:00	975	Performance Testing: Reliability Run.
9/22/09	00:00-24:00	1,111	Performance Testing: Reliability Run.
9/23/09	00:00-00:34 01:08-24:00	1,191	Performance Testing: Reliability Run.
9/24/09	00:00-00:02 1:40-23:56	1,227	Performance Testing: Reliability Run.
9/25/09	05:11-23:24	1,384	Performance Testing: Reliability Run.
9/26/09	03:27-12:19 12:57-24:00	903	Performance Testing: Reliability Run.
9/27/09	00:00-21:06	837	Performance Testing: Reliability Run.
9/28/09	05:11-11:20 12:34-22:32	704	Performance Testing: Reliability Run.
9/29/09	01:31-22:27 23:44-24:00	842	Performance Testing: Reliability Run.
9/30/09	00:00-24:00	1,006	Performance Testing: Reliability Run.
10/1/09	00:00-24:00	1,187	Performance Testing: Reliability Run.

CIP CT-1 Dispatches for Testing and Commissioning			
Date	**Time Spans of CT Operation (approx.)**	**MWH Produced**	**Description of Testing or Commissioning Activity**
10/2/09	00:00-07:53 08:27-15:28 16:02-24:00	980	Performance Testing: Reliability Run.
10/3/09	00:00-24:00	1,590	Performance Testing: Reliability Run.
10/4/09	00:00-00:16 04:04-09:22 10:28-18:48 20:01-24:00	1,070	Performance Testing: Reliability Run.
10/05/09	00:00-07:12	289	Performance Testing: Reliability Run.
10/06/09	14:02-15:09	49	Test of replacement ARC valve (flow control valve for water injection)

Until biofuel is available, the CIP CT-1 unit will be held from use for purposes other than testing unless an emergency condition arises, as defined in the response to PUC IR-117. The table on page 4 lists the date and time of the one instance where the CIP CT-1 unit was dispatched for emergency purposes and a brief description of the system condition that prompted its dispatch.

CIP CT-1 Dispatches for Emergency Purposes			
Date	**Time Spans of CT Operation (approx.)**	**MWH Produced**	**Description of System Condition**
10/09/09	17:17 – 18:21	37	**Generation Condition Level 1**: Kahe 6 shutdown to repair steam leak; Waiau 10 trip due to CO2 fire protection system; high system loads (high temp and little wind); and flash flood advisory. This resulted in a Generation Condition 1. CIP CT-1 was started 5:17 p.m. and reached its minimum output of 40MW at 5:31 p.m. At 6:06 p.m. the emergency condition had been resolved and System Operation began to ramp down CIP CT-1. At 6:21 p.m. CIP CT-1 was taken off-line and was no longer supplying power to the grid. CIP CT-1 supplied power to the grid at its minimum output of 40MW from 5:31 p.m. to 6:06 p.m. (Hawaiian Electric's October 12, 2009 letter to the Commission reported that the CIP CT-1 was taken "off-line" at 6:06 p.m. Although the unit was released at 6:06 p.m., it actually went off-line at 6:21 p.m.)

PUC-IR-155

Please describe and quantify any benefits (such as reserve capacity and ancillary services) that the CT-1 unit currently provides.

HECO Response:

As described in the response to PUC-IR-117, page 14, Hawaiian Electric proposed to call on CIP CT-1 as a last resort generation resource to mitigate spinning reserve and generation capacity shortfall situations that have a high potential to lead to or have already led to load shedding and island wide blackouts.

As reported in the October 12, 2009 letter to the Commission (subject: Emergency Use of Campbell Industrial Part Combustion Turbine No. 1)[1], on October 9, 2009, CIP CT-1 was used for "emergency purposes" (i.e., when the system is in a Generation Condition 1, 2, 3 or 4 condition) to serve system load and to provide additional spinning reserve capacity. Hawaiian Electric uses Generation Condition levels to characterize the amount of excess or shortfall of spinning reserves available at any given time. Use of these levels to describe the state of the system helps to facilitate contingency planning efforts in the event of spinning reserve or generation capacity shortfalls.

As described in HECO ST-7, page 14 to 21, CIP CT-1 provides significant operational value in three general ways:

1) allows Hawaiian Electric to more effectively integrate increasing levels of renewable variable generation resources (such as wind and solar electric energy) into the Oahu grid;
2) eliminates the need to commit up to two other cycling and/or peaking units to provide 30 to 50 MW of generation and 60 to 80 MW of spinning reserve (and achieved firing biodiesel,

[1] For details on the timing and sequence of the operation of CIP CT-1 on October 9, 2009, see Company's response to PUC-IR-154.

and not fossil fuel, thus reducing the "carbon footprint" of the generating system); and

3) delivers on Hawaiian Electric's fundamental "obligation to serve" by maintaining an appropriate and responsible level of firm generating capacity on Oahu.

HECO ST-7 also describes operational characteristics provided by CIP CT-1 that facilitate and support the integration of variable generation resources. Summarized, this includes:

1) capacity to serve the expected system loads up to its rated capacity of 120 MW,
2) dispatchability to maintain a balance between system generation and the system load demand,
3) frequency regulation and regulating reserve to maintain a "cushion" for responding to changes in load demand or power output from generation sources connected to the grid,
4) voltage regulation to control system voltages within proper limits throughout the grid,
5) rotating inertia to enable the electric system to effectively "ride through" the first few seconds of major system disturbances, and
6) CIP CT-1 may also be started and connected to the grid in minutes (compared to hours for the steam units), and it may be dispatched at ramp rates (up and down) that are up to 10 times greater than those for the steam units.

CIP CT-1 will also provide more flexibility in scheduling maintenance outages of the other generating units, including the baseload units, and this will result in fewer megawatt-hours ("MWh") than would otherwise be lost due to extended operation of derated baseload units that require an outage for corrective maintenance.

PUC-IR-158

According to page 12 of HECO ST-15(a):

> "In the Settlement agreement with the other parties, the Company reduced labor expenses by $532,000 to reflect a 2.0% reduction in wage levels... "

According to page 88 of Exhibit HECO T-7:

> "On an annual basis, general wage rates for test year 2009 are expected to be 7.50% (for bargaining unit employees) and 8.55% (for merit employees) higher than the respective 2007 wage rates (see HECO-1105)."

Please confirm or deny that the wage increase in the Proposed Settlement for the 2009 test year from the 2007 wage rates for merit employees is 6.55% (8.55% - 2%). If this is not the case, please describe the size of the expected average increase in merit employee wages.

HECO Response:

The effect of the general pay increase on the relative wage rates in the Settlement Agreement for the 2009 test year for merit employees are 7.14% higher than the relative wage rates for 2007, as shown on HECO-S-1103, page 7. HECO-S-1103, page 7 shows the relative wage rates for merit employees from 2007 to 2009, with the wage rate assumption for 2009 reduced by 2%. The reason the relative wage rate increase from 2007 is not 6.55% (the 8.55% shown in HECO-1105 provided in direct testimony less 2% (8.55% - 2%)) is because the merit employee wage rate assumption for the 2009 test year that was reduced by 2%, was reflected, effective beginning in May 2009, and not for the full year.

PUC-IR-164

According to page 16 of HECO ST-10, the 2009 Test Year HECO advertising expense for the Residential Direct Load Control ("RDLC") program is $424,000, an increase of $126,000 over 2008. HECO contends that the increase "reflects the anticipation that as the water heating portion of the program approaches market saturation more closely, efforts to market the program will become more expensive." With respect to this cost:

(a) Beyond the assumption of higher expenses for reaching the remaining customers, what analysis did HECO conduct to estimate an increase of $126,000 in advertising expenses?

(b) What analysis did HECO conduct to indicate that $424,000 was the appropriate level of RDLC advertising expense?

(c) How has HECO examined whether RDLC advertising expenditures at either the 2008 or 2009 level are cost-effective based on RDLC benefits? Please provide all available documentation of such analyses.

<u>HECO Response:</u>

a. To determine at what program participation level market saturation would occur, Hawaiian Electric relied on its *Residential Water Heater Load Control, A Phone Survey of Residential Customers* survey conducted in 2002 and filed as Exhibit B in the Residential Direct Load Control Program Applications, Docket No 03-0166 filed on June 6, 2003 (Attachment 1 to this response). The results of the survey indicated out of the approximately 84,000 electric resistance water heaters in the marketplace, approximately 32,760 definitely or probably would participate if a $2.50 monthly incentive were offered (Attachment 1 at 6 and 13).

When the test year RDLC Program advertising expense estimate was developed in March 2008, RDLC Program water heating participation was around 29,000, which indicated that market saturation was being approached and that advertising expenses above 2008 levels would be required to meet 2009 participation targets. Actual RDLC Program participation in 2008 was 10,182, of which 9,083 were water heating and 1,099 were central air-conditioning participants, bringing total cumulative RDLC Program water heating participation to over 35,000.

As of the end of September 2009 load control receivers have been installed on approximately 37,000 residential water heaters and 3,900 residential central air-conditioners in the RDLC Program. However, through September 2009, Hawaiian Electric has expended $77,962 in advertising expenses in the RDLC Program and will slightly exceed its RDLC Program participation target of 5,000 this year (which includes about 2,700 water heating participants).[1]

HECO's 2009 target for RDLC Program participation was less than half of the actual installations in the prior year because of the concern that the program was approaching market saturation. In addition, HECO's test year estimate for RDLC Program advertising expense also anticipated that achieving the lower target would necessitate an increase over actual 2008 expenditures. However, demand for the program is higher than expected, resulting in very little need to advertise further to create the required backlog to match the desired installation schedule and budget. With the expectation of mailing up to two status letters to all RDLC participants in October and November 2009 (at an approximate cost of $42,000 for both mailings) that will either announce the extension or termination of the program (depending on the Commission's decision in the RDLC extension proceeding, Docket No. 2009-0097) total 2009 advertising and customer communications expenses for the year are expected to be approximately $120,000. Therefore, Hawaiian Electric no longer maintains that a RDLC Program advertising budget of $424,000 will be necessary to continue to reach

[1] This assumes that the RDLC Program is extended by the Commission in Docket No. 2009-0097 such that HECO can continue to install load control switches under the program without interruption.

the participation goals for the program in 2009. Instead, Hawaiian Electric supports a test year expense estimate for advertising in the RDLC Program of $120,000.

b. As stated in HECO T-10 at page 30, "[r]esidential customers on Oahu have received multiple mailings regarding RDLC program participation and many customers have received in excess of five mailings through the Company's direct mail campaigns. As the number of participants increase, it will be harder to enroll additional participants in the program because most of the remaining customers are likely to be those who have refused previous calls to participate. Thus, more effort will need to be expended to motivate the remaining customers to participate. Telemarketing and other strategies will be tested and more cost-effective tools will be identified to augment or replace the direct mail campaign." The advertising budget of $424,000 was determined to be the appropriate level to allow for telemarketing and other strategies to be tested while still continuing the tradition direct mail approach. However, as stated in its response to part a. above, actual 2009 ytd program performance has demonstrated that a lower RDLC Program test year advertising expense estimate is appropriate.

c. In the RDLC Program Application for Program Extension, Docket No. 2009-0097 filed on April 30, 2009, Hawaiian Electric conducted a cost effectiveness evaluation of the program in years 2010 through 2012 using an advertising budget of $424,000 for each year. That analysis indicated the RDLC Program was cost effective with this level of advertising budget. (See the budget for the RDLC Program for 2010 through 2012, filed as Exhibit A (and shown as Attachment 2 to this response), and the cost effectiveness evaluation, filed as Exhibit D, of the application (and shown as Attachment 3 to this response.))

RESIDENTIAL WATER HEATER LOAD CONTROL

A Phone Survey of Residential Customers

Prepared by

Market Research and Evaluation Division
Energy Services Department
Hawaiian Electric Company, Inc.

July 8, 2002

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EXECUTIVE SUMMARY

This report presents the results of a telephone survey to assess the market potential for a proposed Residential Water Heater Load Control Program. The Program would recruit residential customers in order to install electronic control devices on their respective water heaters to allow turning off their electric resistance water heater during periods of high demand. This study seeks to determine the prospective number of participants that might be expected from different levels of incentive.

The telephone survey among a sample of 400 residential customers was conducted April 12-20, 2002. The sample was drawn at random from the population of residential accounts active as of February 2002. The customers who were reached were screened to select those who indicated that they have an electric resistance water heater that is at least 40 gallons and is not located under a counter.

Based on the percentage of respondents in the telephone survey who stated that for an incentive of $1.00 per month, they would "definitely" participate in the program, it is projected that 6,490 of HECO's residential customers would participate in the program at that incentive level. The majority (4,400) of this "$1.00-per-month" projection would have water heater tanks in the 40-60 gallon range. The projection would increase by 3,780, to a total of 10,270, if the incentive were $2.50 per month. Again, the majority (6,500) of this "$2.50-per-month" projection would have water heater tank sizes in the 40-60 gallon range. At an incentive level of $5.00 per month, the projected number of HECO's residential customers who would participate in the program is 21,800. Of this $5.00-per-month projection, 13,200 would have water heater tank sizes in the 40-60 gallon range.

Analysis of survey further indicates that the number of participants in an air conditioning load control program would be extremely limited. Only 5% of those surveyed had central air conditioning. Of those respondents with central air conditioning, only 7% would definitely participate in such a program. This represents less than a 0.4% overall participation rate. However, the small number of survey respondents with central air conditioning makes projections of participation rates unreliable.

Table 1: Load Control Device Market Penetration Summary

Segment	Population	Definitely Would				Definitely/Probably Would			
		$1.00	$2.50	$5.00	Total	$1.00	$2.50	$5.00	Total
40-60 gal.	46,800	4,400	2,100	6,700	13,200	16,170	2,290	6,090	24,550
60+ gal.	9,500	420	420	1,470	2,310	2,740	1,700	420	4,860
Don't Know Tank Size	27,700	1,670	1,260	3,360	6,290	8,600	1,260	2,090	11,950
Total	84,000	6,490	3,780	11,530	21,800	27,510	5,250	8,600	41,360

PUC-IR-164
DOCKET NO. 2008-0083
ATTACHMENT 1
PAGE 6 OF 46

BACKGROUND AND OBJECTIVES

The purpose of this study was to determine the market potential for a proposed Residential Water Heater Load Control Program. This program utilizes remotely operated switches to turn off and on residential customer water heaters. The Research & Evaluation Division commissioned Ward Research to assist with the development of a survey and the fielding of that survey. Customers were drawn at random from the population of active residential accounts and then screened to select those who indicated that they have an electric resistance water heater that is at least 40 gallons and is not located under a counter. The overall objective of the study was:

TO DETERMINE THE ADOPTION RATES FOR THE PROGRAM AT DIFFERENT LEVELS OF INCENTIVE.

The specific aims of the study were:

- To estimate the percentages of customers that would join the program at three levels of incentive: $1.00 per month, $2.50 per month, and $5.00 per month.
- To determine reasons for nonparticipation.
- To describe the demographic composition of the survey respondents.
- To investigate potential and acceptance of a similar program directed at residential central air conditioning.

NARRATIVE OF FINDINGS

PART A: WATER HEATER LOAD CONTROL

I. Program Participation

The proposed water heater load control program was explained to survey respondents as follows:

"This program would help HECO manage the demand for electricity at peak times. HECO would install a switch on your water heater that would be controlled electronically from outside your home. Your water heater could be turned off for periods of up to one hour each time and no more than six times a year. And they may not even need to turn off your water heater. In fact, most participants in the program will never notice any change in their hot water supply.

The installation of the switch on your water heater would be done at your convenience and at no cost to you. You may drop out of the program at no cost to you at any time. And, for your convenience, if your heater is turned off, you'll have a manual switch at home to turn it back on.

In return for your participation, one dollar will be taken off your electric bill every month, even if your water heater is never actually turned off."

To assess program participation, respondents were asked their likelihood of participating in this program if one (1) dollar is taken off their electric bill every month, even if their water heater is never actually turned off. As indicated below in Figure 1, one out of three respondents (32.8%) indicated that they would participate in this program. Similarly, one in three (33.8%) would definitely not or probably not participate. Most of these respondents say that they probably/definitely would not participate due to reasons such as "pleased with the way things are now" or "the savings are insignificant." (Table 2)

Figure 1: Participation - $1

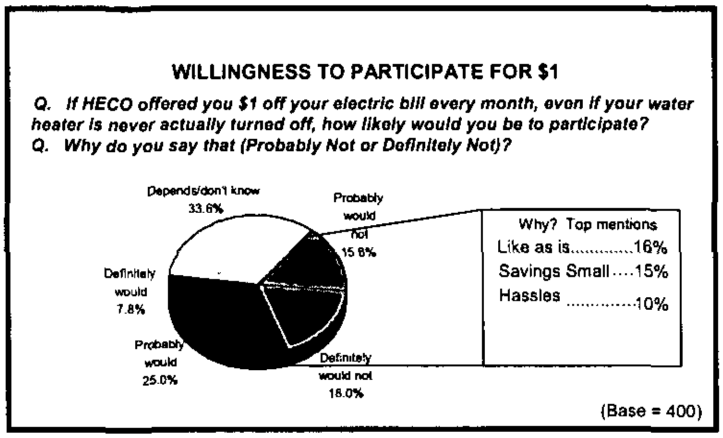
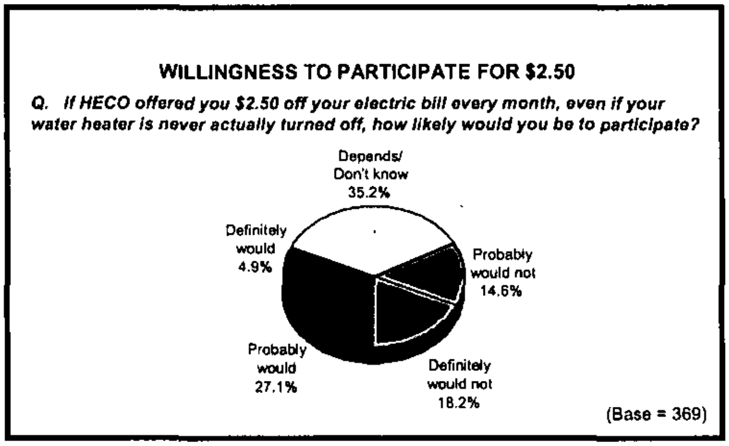


Table 2: Top Reasons For Not Participating In Water Heater Program

Why do you say you would (probably/definitely) not participate?	Percent
Don't want changes/like it the way it is	16.1%
Bill is small/Don't care about saving/not used often	14.8%
Don't want complication/hassle	10.1%
See no benefit/$1 is small	9.4%

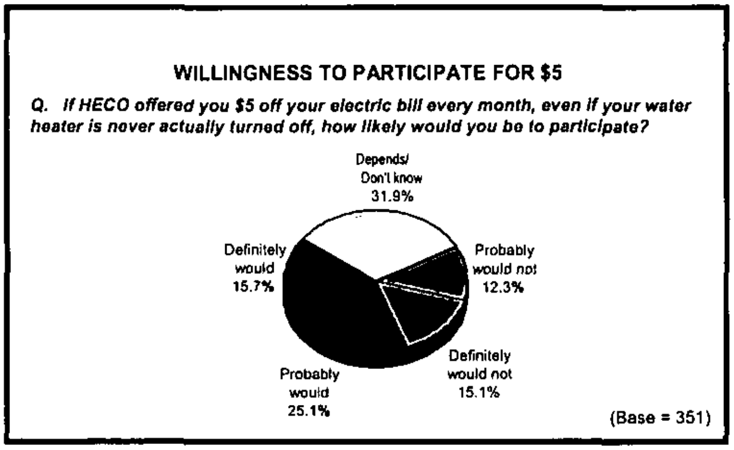
All respondents, other than those who indicated that they would "definitely" participate in the program for a $1.00 per month incentive, were then asked whether they would participate if offered a $2.50 per month incentive. As indicated below in Figure 2, almost one out of three (32.0%) of these respondents indicated that they would "definitely" or "probably" participate in this program if HECO offered them $2.50 off their electric bill each month. One in three (32.8%) would "definitely not" or "probably not" participate.

Figure 2: Participation - $2.50



As a final offer to access the level of participation, respondents, other than those who indicated that they would "definitely" participate in the program for either a $1.00-per-month or a $2.50-per-month incentive, were then asked whether they would participate in this program if five (5) dollars were taken off their electric bill every month. Based on this offer, shown in Figure 3, two out of five (40.8%) of these respondents indicated that they would "definitely" or "probably" participate in this program at that level of compensation. Almost one in four (27.4%) say that they would "definitely not" or "probably not" participate.

Figure 3: Participation - $5



Applying survey respondents' stated intentions, as shown in Table 3, to the population of Oahu electric water heaters:

- At $1.00, there would be 6,490 customers who would "definitely" participate.
- At $2.50, an additional 3,780 customers, or 10,270 in total, would "definitely" participate.
- At $5.00, an additional 11,530 customers, or 21,800 in total, would "definitely" participate.

Depending on how aggressively the program is marketed, the expected market penetration may include "probably buy" respondents. In that case:

- At $1.00, there would be 27,510 customers who would "definitely or probably" participate.

- At $2.50, an additional 5,250 customers, or 32,760 in total, would "definitely" or "probably" participate.

- At $5.00, an additional 8,600 customers, or 41,360 in total, would "definitely" or "probably" participate.

The majority of electric water heater tanks are in the 40-60 gallon range. Of the estimated 84,000 electric water heaters on Oahu, an estimated 46,800 of them are in that tank size category. Only about 10% of all electric water heaters are estimated to be 60 gallons or larger. A significant number of electric water heater owners (27,700) do not know their water heater tank size.

These results are summarized in Tables 3 and 4 and Figure 4, below.

Table 3: Load Control Device Market Penetration

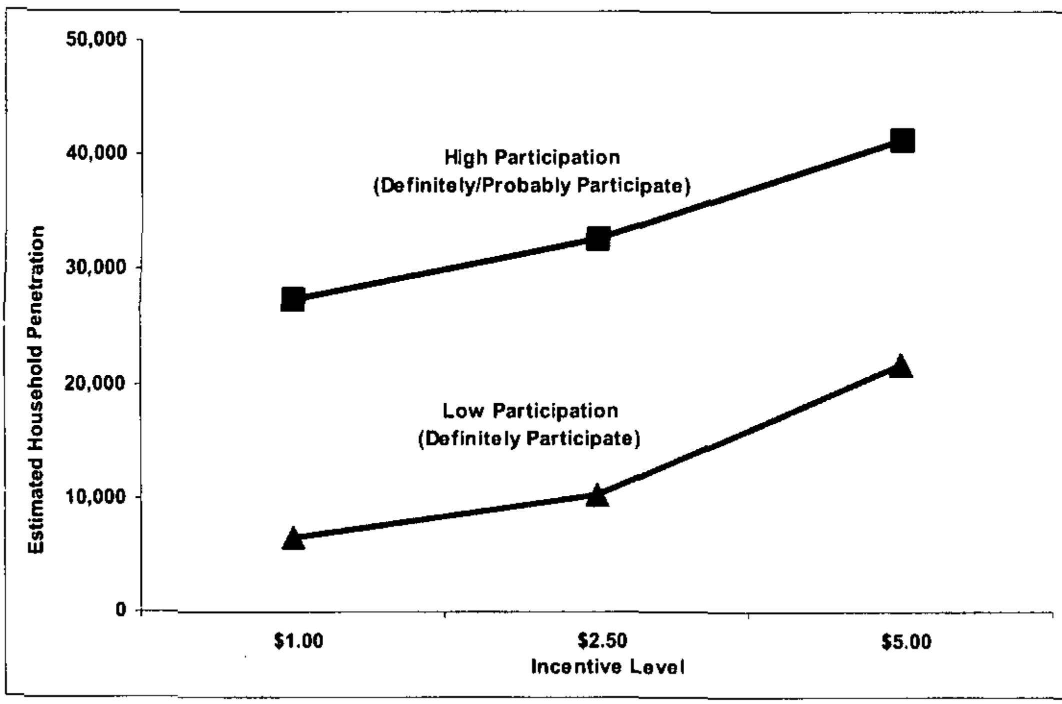
		ESTIMATED PENETRATION BASED ON PERCENTAGE						ESTIMATED PENETRATION BASED ON COUNT							
		DEFINITELY WOULD			DEFINITELY/PROBABLY WOULD			DEFINITELY WOULD				DEFINITELY/PROBABLY WOULD			
		Low Participation			High Participation			Low Participation				High Participation			
With Timer	Population	$1.00	$2.50	$5.00	$1.00	$2.50	$5.00	$1.00	$2.50	$5.00	TOTAL	$1.00	$2.50	$5.00	TOTAL
40-60 gal.	18,000	10.5	5.8	19.8	33.7	9.3	14.0	1,890	1,040	3,560	6,490	6,070	1,670	2,520	10,260
60+ gal.	5,700	3.7	7.4	3.7	14.8	22.2	3.7	210	420	210	840	840	1,270	210	2,320
Don't Know Tank Size	6,700	3.1	9.4	0.0	25.0	3.1	6.3	210	630	-	840	1,680	210	420	2,310
Total	**30,400**							**2,310**	**2,090**	**3,770**	**8,170**	**8,590**	**3,150**	**3,150**	**14,890**
Without Timer															
40-60 gal.	27,100	8.5	3.9	11.6	35.7	2.3	12.4	2,300	1,060	3,140	6,500	12,638	814	4,390	17,842
60+ gal.	3,400	6.3	0.0	31.3	50.0	12.5	6.3	210	-	1,060	1,270	2,200	550	277	3,027
Don't Know Tank Size	17,400	7.2	3.6	19.3	36.1	4.8	8.4	1,250	630	3,360	5,240	8,231	1,094	1,915	11,240
Total	**47,900**							**3,760**	**1,690**	**7,560**	**13,010**	**23,069**	**2,458**	**6,582**	**32,109**
Don't Know If Have Timer															
40-60 gal.	1,700	12.5	0.0	0.0	25.0	0.0	12.5	210	-	-	210	430	-	210	640
60+ gal.	400	0.0	0.0	50.0	50.0	0.0	0.0	-	-	200	200	200	-	-	200
Don't Know Tank Size	3,600	5.9	0.0	0.0	17.7	5.9	5.9	210	-	-	210	640	210	210	1,060
Total	**5,700**							**420**	**-**	**200**	**620**	**1,270**	**210**	**420**	**1,900**
TOTAL															
40-60 gal.	46,800	9.4	4.5	14.3	34.6	4.9	13.0	4,400	2,100	6,700	13,200	16,170	2,290	6,090	24,550
60+ gal.	9,500	4.4	4.4	15.5	28.8	17.9	4.4	420	420	1,470	2,310	2,740	1,700	420	4,860
Don't Know Tank Size	27,700	6.0	4.5	12.1	31.0	4.5	7.5	1,670	1,260	3,360	6,290	8,600	1,260	2,090	11,950
Total	**84,000**	**7.7**	**4.5**	**13.7**	**32.8**	**6.3**	**10.2**	**6,490**	**3,780**	**11,530**	**21,800**	**27,510**	**5,250**	**8,600**	**41,360**

Table 4: Load Control Device Cumulative Market Penetration

Likelihood of Participation	Monthly Incentive		
	$ 1.00	$ 2.50	$ 5.00
Definitely or Probably Participate	27,510	32,760	41,360
Definitely Participate	6,490	10,270	21,800

*Cumulative at each level increase in incentive

Figure 4: Load Control Device Cumulative Market Penetration

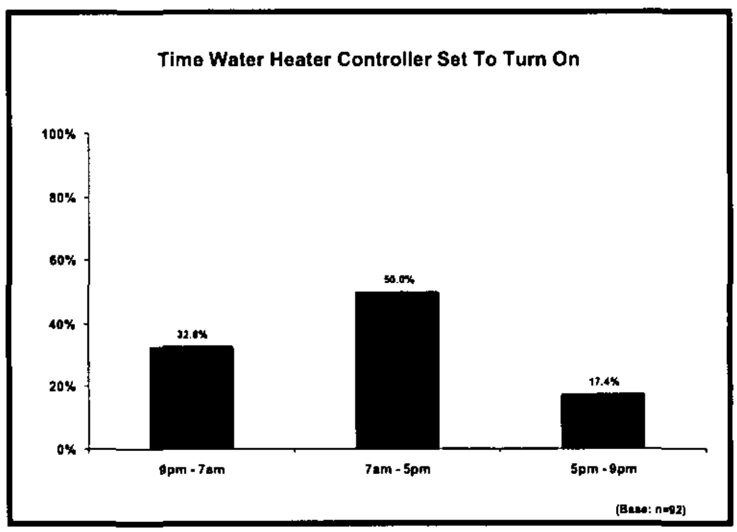


II. Electric Water Heater Timer

Of the 400 respondents included in this study, one out of three (36.3%) indicated that their electric water heater is controlled by a timer that can be set or changed.

As shown in Figure 5, one half (50.0%) of the respondents indicated that their timer is set to turn on between the hours of 7am to 5pm.

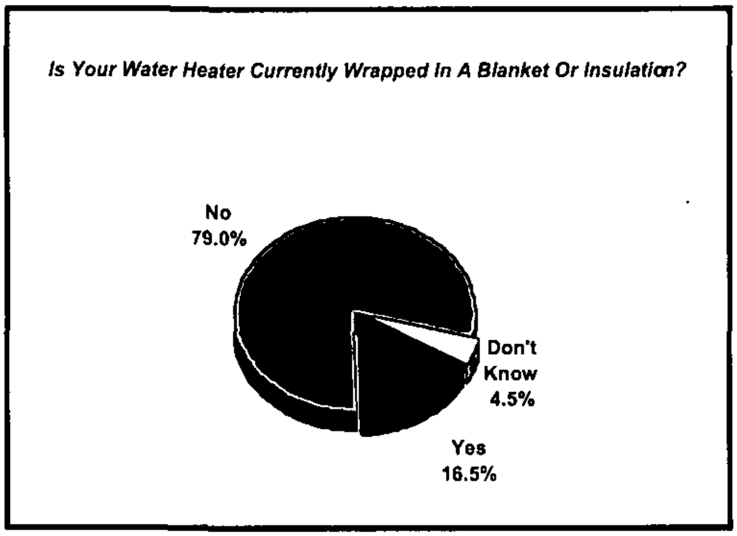
Figure 5: Water Heater Timer



III. Insulation

When respondents were asked if their electric water heater is currently wrapped in a blanket or insulation, eight out of ten (79.0%) respondents indicated *"no."*

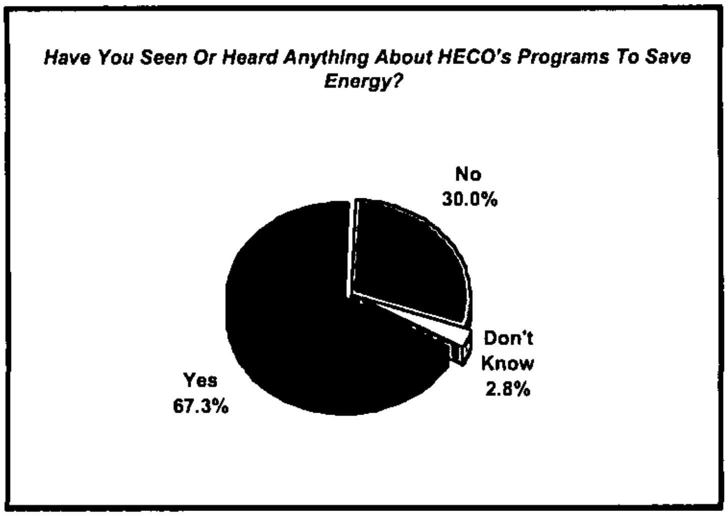
Figure 6: Water Heater Blanket



IV. Program Awareness

Since 1996, HECO has promoted Customer Efficiency Programs through television ads, print advertisements, and related promotional materials. When respondents were asked if they were aware of cost savings programs offered by HECO, two out of three respondents (67.3%) indicated "yes."

Figure 7: Awareness Of Programs



PART B: AIR CONDITIONING

I. Program Participation

HECO is also considering a program that proposes to install a switch on residential central air-conditioning thermostats that would be controlled electronically from outside the home. To survey respondents who indicated that they live in a single-family home (n= 295), the program was presented with this statement:

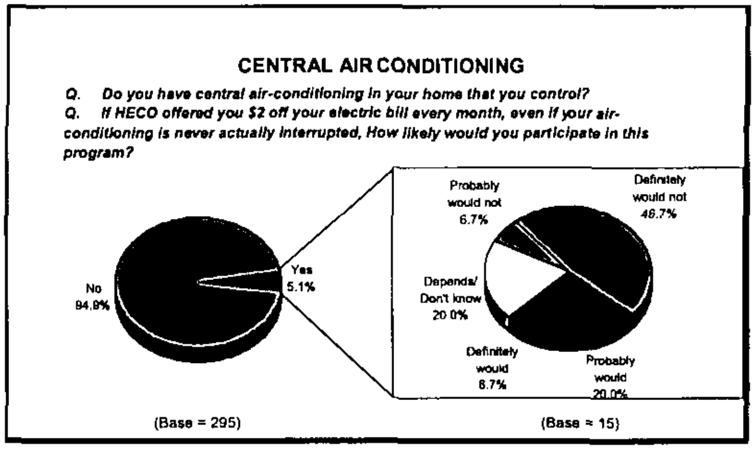
"HECO is also considering a similar program for air-conditioning.

At your convenience and at no cost to you, they would install a switch on your thermostat that they would control electronically from outside your home. They would probably need to interrupt your air-conditioning for no more than one hour, no more than six times a year.

In return for being able to turn up your thermostat as needed, they would take two dollars off your electric bill every month, whether they interrupted your service or not."

To assess participation in this program, respondents were asked their likelihood to partake in this program if two (2) dollars is taken off their electric bill every month, even if their central air-conditioning is never interrupted. As indicated below in Figure 8, fewer than one out of ten respondents (5.1%) indicated that they have central air-conditioning that can be controlled. Of those who have indicated that they have central air-conditioning (n=15), more than one half (or 53.4%) said that they would definitely not or probably not participate in this program. A minority, fewer than three in ten (26.7% - only four respondents) would definitely or probably participate. Given the low occurrence of central air conditioning in the sample, the numbers are too small to draw conclusions or project to the overall population.

Figure 8: Participation (AC)



APPENDICES

Research Methodology
Sample Design
Data Tabulations
Survey Instrument

RESEARCH METHODOLOGY

To best accomplish the objectives of this study, a telephone survey among Hawaiian Electric Company (HECO) residential customers was conducted during April 12-20, 2002. A total of 400 interviews was completed.

The questionnaire used in this research was developed by Ward Research and HECO. Average survey length was 6.4 minutes, and a copy of the questionnaire is included in the Appendix.

Prior to interviewing, HECO provided a random extract of active residential customer accounts, from HECO's billing system, as of February 2002 to Ward Research. The extract contained residential customer names and last known telephone numbers, for which Ward Research coordinated telephone number look-up and verification of listed phone numbers.

All interviewing was conducted from the Ward Research Calling Center in the downtown Honolulu office, which is equipped with a Computer Assisted Telephone Interviewing (CATI) system. Interviews were conducted between the hours of 5:00 p.m. and 8:30 p.m. on week nights, 9:00 a.m. to 5:00 p.m. on Saturdays, and between 10:00 a.m. and 6:00 p.m. on Sundays. The Calling Center allows for the 100% monitoring of calls, through a combination of electronic and observational means.

The interviews were conducted with the household member most familiar with the electric bill. Up to five (5) attempts were made to reach each telephone number called. The customers who were reached were screened to select those who indicated that they have an electric resistance water heater that is at least 40 gallons and is not located under a counter. Interviews were completed with 20.8% of the phone numbers that were reached.

Program Participation Estimation

Located within this report are estimates of program participation electric water heater load control devices, based both on percentage (%) and counts, and devised from questionnaire responses from this survey and HECO's 2000 Residential Appliance Survey (RAS). From the RAS, it was estimated that 71,000 HECO customers have electric water heaters with a tank capacity between 40 to 60 gallons, and 13,000 customers with a tank capacity over 60 gallons. The estimated numbers of residential customers who have a timer controlled electric water heater, based on tank size, were then calculated.

The total number of potential program participants was estimated for two scenarios, low and high penetration. Low penetration estimates are based on the percentages of just those respondents who said they "Definitely" would participate at a given price point.

High penetration estimates are base on percentages of respondents who said they "Definitely" or "Probably" would participate at a given price point. If a "Definite" or "Probably" would participate response was given at more than one price point, the lowest price point was used.

DATA TABULATIONS

Table C-1: Water Heater Characteristics

	Number	Percent
How many electric water heaters do you have?		
1	372	93.0%
2	25	6.3%
3	2	0.5%
4	1	0.3%
What is the capacity of your water heater?		
40 to 60 gallons	223	55.8%
over 60 gallons	45	11.3%
Don' Know	132	33.0%
Where is your water heater located?		
In the house	142	35.5%
In the garage	94	23.5%
Outside the house	163	40.8%
Don't Know	1	0.3%
Age of your water heater		
Less that one year	26	6.5%
1 to 5 years	134	33.5%
6 to 10 years	103	25.8%
11+ years	61	15.3%
Don't know	76	19.0%
Base (n)	400	100.0%

Table C-2: Electric Water Heater Timer

	Number	Percent
Is your water heater currently:		
Controlled by a timer that you can set or change?		
Yes	145	36.3%
No	228	57.0%
Don't Know	27	6.8%
Base (n)	400	100.0%
Know what time timer set to turn on?		
Yes	92	63.4%
No	32	22.1%
Don't Know	21	14.5%
Base (n)	145	100.0%
What time is your heater set to turn on?		
9pm to 7am	30	32.6%
7am to 5pm	46	50.0%
5pm to 9pm	16	17.4%
Base (n)	92	100.0%

Table C-3: Water Heater Insulation

	Number	Percent
Is your electric water heater wrapped in a blanket		
Yes	66	16.5%
No	316	79.0%
Don't know	18	4.5%
Base (n)	400	100.0%

Table C-4: Awareness of HECO Energy Saving Programs

	Number	Percent
Have you seen or heard anything about HECO's programs to save energy?		
yes	269	67.3%
no	120	30.0%
don't know	11	2.8%
Base (n)	400	100.0%

Table C-5: Likeliness to Participate In This Energy Saving Program

	Number	Percent
If you had a choice, would you choose to participate in this water heater program for $1?		
definitely would NOT	72	18.0%
probably would NOT	63	15.8%
maybe/maybe not	107	26.8%
probably WOULD choose	100	25.0%
definitely WOULD choose	31	7.8%
don't know	27	6.8%
Base (n)	400	100.0%
If you had a choice, would you choose to participate in this water heater program for $2.50?		
definitely would NOT	67	18.2%
probably would NOT	54	14.6%
maybe/maybe not	103	27.9%
probably WOULD choose	100	27.1%
definitely WOULD choose	18	4.9%
don't know	27	7.3%
Base excludes "definitely would participate" at a lower price (n)	369	100.0%
If you had a choice, would you choose to participate in this water heater program for $5.00?		
definitely would NOT	53	15.1%
probably would NOT	43	12.3%
maybe/maybe not	86	24.5%
probably WOULD choose	88	25.1%
definitely WOULD choose	55	15.7%
don't know	26	7.4%
Base excludes "definitely would participate" at a lower price (n)	351	100.0%

Table C-6: Reason for not participating in water heater program

	Number	Percent
Why do you say you would (probably/definitely) not participate?		
Don't want changes/like it the way it is	24	16.1%
Bill is small/Don't care about saving/not used often	22	14.8%
Don't want complication/hassle	15	10.1%
See no benefit/$1 is small	14	9.4%
Not interested/No reason/No need	13	8.7%
I want control/Don't want HECO controlling	12	8.1%
Use heater all time/never want it off/unpredictable	11	7.4%
I have a timer/timer works fine	11	7.4%
Rent/Need to ask landlord	6	4.0%
Not familiar with program	5	3.4%
Up to others in household to decide	4	2.7%
Plan to replace heater/go solar	3	2.0%
Big brother/invasion of privacy code	3	2.0%
Other	6	4.0%
Base (n)	135	100.0%

*Multiple response

Table C-7: Program For Air Conditioning

	Number	Percent
Do you have central air conditioning (single family dwelling) that you control?		
yes	15	5.1%
no	280	94.9%
Base (n)	295	100.0%
If you had a choice, would you choose to participate in this A/C program for $2?		
definitely would NOT	7	46.7%
probably would NOT	1	6.7%
maybe/maybe not	3	20.0%
probably WOULD choose	3	20.0%
definitely WOULD choose	1	6.7%
don't know	0	0.0%
Base (n)	15	100.0%

Table C-8: Area of Residences

	Number	Percent
Windward	62	15.5%
Moanalua/Aiea/Pearl City	55	13.8%
Urban Honolulu	107	26.8%
Ewa Plain	21	5.3%
East Honolulu	72	18.0%
North Shore	9	2.3%
Central Oahu	62	15.5%
Leeward	12	3.0%
Base (n)	400	100.0%

Table C-9: Type of Residences

	Number	Percent
Own or rent home		
own	328	82.0%
rent	69	17.3%
occupy without payment	1	0.3%
don't know/refused	2	0.5%
Base (n)	400	100.0%
Type of home		
house	295	73.8%
apartment/condo	49	12.3%
townhouse	41	10.3%
multi-family house	15	3.8%
don't know/refused	0	0.0%
Base (n)	400	100.0%

Table C-10: Demographic Characteristics of Respondents

	Number	Percent
Ethnicity		
Japanese	130	32.5%
Caucasian	*105*	*26.3%*
Hawaiian	47	11.8%
Chinese	37	9.3%
Filipino	33	8.3%
mixed, not Hawaiian	24	6.0%
other	17	4.3%
don't know/refused	7	1.8%
Years in Hawaii		
less than 1 year	2	0.5%
1 to 5 years	12	3.0%
6 to 20 hears	41	10.3%
over 20, not lifetime	111	27.8%
lifetime	233	58.3%
don't know	1	0.3%
Age		
18 to 24	3	0.8%
25 to 34	26	6.5%
35 to 44	56	14.0%
45 to 54	72	18.0%
55 to 64	82	20.5%
65 plus	135	33.8%
refused	26	6.5%
Annual household income		
less than $20,000	34	8.5%
$20,000 to $30,000	41	10.3%
$30,000 to $50,000	82	20.5%
$50,000 to $100,000	96	24.0%
more than $100,000	48	12.0%
Don't know/refused	99	24.8%
Gender		
male	160	40.0%
female	240	60.0%
Bases (n)	400	100.0%

Table C-11: Market Characteristics: Definitely or Probably Would Participate (Percent)

If you had a choice, would you choose to participate in this water heater program for:					
	$1.00	$2.50	$5.00	Would Not Participate	Total
Area of residence					
Windward	11.4	**21.1**	13.3	17.2	15.5
Moanalua/Aiea/Pearl City	**20.0**	5.3	12.6	14.3	13.8
Urban Honolulu	22.9	26.3	27.3	27.1	26.8
Ewa Plain	2.9	10.5	6.3	4.4	5.3
East Honolulu	14.3	15.8	16.1	20.2	18.0
North Shore	5.7	5.3	2.8	1.0	2.3
Central Oahu	**20.0**	15.8	16.8	13.8	15.5
Leeward	2.9	0.0	4.9	2.0	3.0
Controlled by timer that can be set/changed					
Yes	40.0	**57.9**	32.2	36.5	36.3
No	54.3	42.1	62.9	54.7	57.0
Don't know	5.7	0.0	4.9	8.9	6.8
Water heater wrapped in					
Yes	20.0	10.5	15.4	17.2	16.5
No	74.3	84.2	81.1	77.8	79.0
Don't know	5.7	5.3	3.5	4.9	4.5
Aware about HECO's energy savings programs					
Yes	**82.9**	**78.9**	**69.9**	61.6	67.3
No	17.1	21.1	27.3	35.0	30.0
Don't know	0.0	0.0	2.8	3.4	2.8
Number of people in household					
1	22.9	10.5	12.7	13.4	13.9
2	51.4	47.4	35.2	37.3	38.3
3	8.6	15.8	19.7	16.9	17.1
4	2.9	26.3	15.5	18.4	16.4
5 or more	14.3	0.0	16.9	13.9	14.4
Bases (%)	100.0	100.0	100.0	100.0	100.0

Table C-12: Market Characteristics: Definitely or Probably Would Participate (Percent)

If you had a choice, would you choose to participate in this water heater program for:					
	$1.00	$.2.50	$5.00	Would Not Participate	Total
Length of residence in Hawaii					
Less than 20 years	5.7	0.0	16.1	14.9	13.8
20+ years, not lifetime	**42.9**	**47.4**	28.7	22.8	27.8
lifetime resident	51.4	52.6	55.2	62.4	58.4
Do you own or rent your home?					
Own	**62.9**	**100.0**	**83.7**	83.7	82.6
Rent	37.1	0.0	16.3	16.3	17.4
Ethnicity (three categories)					
Caucasian	**41.2**	36.8	28.7	21.8	26.7
Japanese	23.5	**42.1**	26.6	38.6	33.1
All other	35.3	21.1	44.8	39.6	40.2
Collapsed age categories					
18-44	14.7	21.1	31.6	17.8	22.7
45-54	29.4	15.8	19.9	17.3	19.3
55-64	29.4	15.8	21.3	21.6	21.9
65+	26.5	**47.4**	27.2	43.2	36.1
Collapsed annual household income categories					
Less than $30,000	21.2	23.5	22.0	28.6	24.9
$30,000 - $50,000	21.2	**35.3**	30.5	24.8	27.2
$50,000 - $100,000	**42.4**	29.4	28.8	32.3	31.9
$100,000+	15.2	11.8	18.6	14.3	15.9
Gender					
Male	**51.4**	31.6	41.3	37.9	40.0
Female	48.6	**68.4**	**58.7**	62.1	60.0
Bases (%)	100.0	100.0	100.0	100.0	100.0

Table C-13: Market Characteristics: Definitely Would Participate (Percent)

If you had a choice, would you choose to participate in this water heater program for:					
	$1.00	$2.50	$5.00	Would Not Participate	Total
Area of residence					
Windward	12.9	16.7	10.9	16.6	15.5
Moanalua/Aiea/	22.6	5.6	14.5	13.2	13.8
Urban Honolulu	19.4	27.8	40.0	25.0	26.8
Ewa Plain	3.2	11.1	3.6	5.4	5.3
East Honolulu	16.1	16.7	12.7	19.3	18.0
North Shore	6.5	5.6	3.6	1.4	2.3
Central Oahu	19.4	16.7	12.7	15.5	15.5
Leeward	0.0	0.0	1.8	3.7	3.0
Controlled by timer that can be set/changed					
Yes	35.5	55.6	32.7	35.8	36.3
No	58.1	44.4	65.5	56.1	57.0
Don't know	6.5	0.0	1.8	8.1	6.8
Water heater wrapped in blanket/insulation					
Yes	16.1	11.1	20.0	16.2	16.5
No	77.4	83.3	72.7	80.1	79.0
Don't know	6.5	5.6	7.3	3.7	4.5
Aware About HECO's energy savings programs					
Yes	87.1	77.8	72.7	63.5	67.3
No	12.9	22.2	27.3	32.8	30.0
Don't know	0.0	0.0	0.0	3.7	2.8
Number of people in household					
1	22.6	11.1	14.5	13.0	13.9
2	58.1	44.4	30.9	37.2	38.3
3	9.7	16.7	29.1	15.7	17.1
4	3.2	27.8	10.9	18.1	16.4
5 or more	6.5	0.0	14.5	16.0	14.4
Bases (%)	100.0	100.0	100.0	100.0	100.0

Table C-14: Market Characteristics: Definitely Would Participate (Percent)

If you had a choice, would you choose to participate in this water heater program for:					
	$1.00	$2.50	$5.00	Would Not Participate	Total
Length of residence in Hawaii					
Less than 20 years	6.5	0.0	14.5	15.3	13.8
20+ years, not lifetime	41.9	50.0	23.6	25.8	27.8
lifetime resident	51.6	50.0	61.8	59.0	58.4
Do you own or rent your home?					
Own	61.3	100.0	81.1	84.1	82.6
Rent	38.7	0.0	18.9	15.9	17.4
Ethnicity (three categories)					
Caucasian	41.9	38.9	27.3	24.2	26.7
Japanese	25.8	44.4	32.7	33.2	33.1
All other	32.3	16.7	40.0	42.6	40.2
Collapsed age categories					
18-44	12.9	22.2	28.3	22.8	22.7
45-54	29.0	16.7	18.9	18.4	19.3
55-64	29.0	16.7	24.5	21.0	21.9
65+	29.0	44.4	28.3	37.9	36.1
Collapsed annual household income categories					
Less than $30,000	20.0	25.0	24.4	25.7	24.9
$30,000 - $50,000	20.0	31.3	35.6	26.2	27.2
$50,000 - $100,000	43.3	31.3	17.8	33.3	31.9
$100,000+	16.7	12.5	22.2	14.8	15.9
Gender					
Male	58.1	33.3	41.8	38.2	40.0
Female	41.9	66.7	58.2	61.8	60.0
Bases (%)	100.0	100.0	100.0	100.0	100.0

SURVEY INSTRUMENT

WARD RESEARCH, INC.

HAWAIIAN ELECTRIC COMPANY RESIDENTIAL CUSTOMER SURVEY
WR2895

Record Number____________________ (v01)

Interviewer Name________________________ Time Ended_______________________

Date__________________ I.D.# _______(v02) Time Started______________________

Respondent Name______________________ Total Minutes____________________(v03)

Respondent Phone Number [redacted] (v04)

****

I'm (______________________) from Ward Research, a professional market research firm here in Honolulu. We're calling on behalf of Hawaiian Electric Co. --- or HECO. We're doing a quick survey among their customers, and I'd like to ask you a few questions, if I may. First, let me verify that this is the (INSERT LAST NAME) household? And are you the person in the household most familiar with the electric bill? (IF NO, ASK TO SPEAK WITH THAT PERSON)

S1. First, do you or does anyone in your household work in...**(READ ENTIRE ✓ LIST, PAUSING AFTER EACH TO GET RESPONSE.)**

		No	Yes
✓	Hawaiian Electric Company	2	1
✓	Market research	2	1
✓	The gas company	2	1
✓	Consumer Advocate's Office	2	1
✓	Energy Office at DBEDT	2	1

IF 'YES' TO ANY, THANK KINDLY & TERMINATE.

S2. What type of water heater do you have? Is it: **(READ LIST)**

Electric 01
Gas .... 02 **(TERMINATE)**
Solar .... 03 **(TERMINATE)**
Heat Pump .... 04 **(TERMINATE)**
Other .... 05 **(TERMINATE)**
Don't know .... 09 **(TERMINATE)**

S2a. **(IF HAVE MORE THAN ONE in S2 ASK)** What type of water heater do you use most often?

Electric 01
Gas .... 02 **(TERMINATE)**
Solar .... 03 **(TERMINATE)**
Heat Pump .... 04 **(TERMINATE)**
Other .... 05 **(TERMINATE)**
Don't know .... 09 **(TERMINATE)**

S2b. How many water heaters do you have?

RECORD THE NUMBER OF WATER HEATERS THEY HAVE #_______)

(IF HAVE MORE THAN ONE, READ FOLLOWING SCRIPT OTHERWISE SKIP TO S3)

Now please think about the electric water heater you use the most.....

S3. What is the capacity of your water heater? Is it: **(READ LIST)**

Less than 40 gallons....................01 **(TERMINATE)**
40 to 60 gallons....................02
over 60 gallons....................03
Don't Know....................09

S4. Where is your water heater located? Is it: **(READ LIST)**

In the house....................01
In garage....................02
Outside house....................03
Don't Know....................09

S5. And is it located under a counter?

Yes....................01 **(TERMINATE)**
No....................02
Don't know....................09

Q1. As far as you know, how old is your water heater?

_______ years **(RECORD "0" IF LESS THAN ONE YEAR)**

Q2. Is your water heater currently:

a. Controlled by a timer that you can set or change?

Yes .... 01 CONTINUE
No .... 02 SKIP TO Q2d.
Don't know .... 03 SKIP TO Q2d.

b. (IF YES) Do you know what time it's set to turn on?

Yes .... 01 CONTINUE
No .... 02 SKIP TO Q2d.
Don't know .... 03 SKIP TO Q2d.

c. (IF YES) And what time is that? _______________ AM/PM

d. And is your water heater currently wrapped in a blanket or insulation?

Yes 01
No 02
Don't know 03

Q3. Have you seen or heard anything about HECO's programs to save energy?

Yes 01
No 02
Don't know 09

Next I'll read you a description of a new program HECO is considering. Please bear with me while I read it to you.........

This program would help HECO manage the demand for electricity at peak times. HECO would install a switch on your water heater that would be controlled electronically from outside your home. Your water heater could be turned off for periods of up to one hour each time and no more than six times a year. And they may not even need to turn off your water heater. In fact, most participants in the program will never notice any change in their hot water supply.

The installation of the switch on your water heater would be done at your convenience and at no cost to you. You may drop out of the program at no cost to you at any time. And, for your convenience, if your heater is turned off, you'll have a manual switch at home to turn it back on.

In return for your participation, one dollar will be taken off your electric bill every month, even if your water heater is never actually turned off.

Q4. Okay. If they offered this program, how likely would you be to participate? Would you: **(READ LIST)**

Definitely participate.. 05 **(SKIP TO Q7)**
Probably... 04 **(SKIP TO Q5)**
Maybe/maybe not .... 03 **(SKIP TO Q5)**
Probably not .... 02 **(GO TO Q4a.)**
Definitely not participate ....01 **(GO TO Q4a.)**
Don't know ....09 **(GO TO Q5)**

Q4a. **(IF PROBABLY NOT OR DEFINITELY NOT)** Why do you say you would (probably/definitely) not participate?

Q5. What if they offered you $2.50 **(READ: TWO DOLLARS AND FIFTY CENTS)** off your electric bill every month... how likely would you be to participate? Would you:

Definitely participate	5	**(SKIP TO Q7)**
Probably	4	**(CONTINUE)**
Maybe/maybe not	3	✓
Probably not	2	✓
Or definitely not participate	1	✓
Don't know	9	

(CATI PROGRAMMER: VALUE IN Q5 MUST BE GREATER THAN OR EQUAL TO ANSWER IN Q4)

Q6. What if they offered you $5 off your electric bill every month… how likely would you be to participate? Would you:

Definitely participate	5	**(CONTINUE)**
Probably	4	✓
Maybe/maybe not	3	✓
Probably not	2	✓
Or definitely not participate	1	✓
Don't know	9	

Q7. Do you live in…

An apartment or condominium	1	**(SKIP TO Q10)**
A townhouse	2	**(SKIP TO Q10)**
A single-family detached house	3	**(CONTINUE)**
A multi-family house	4	**(SKIP TO Q10)**

Q8. Do you have central air-conditioning that you control?

Yes	01	**(CONTINUE)**
No	02	**(SKIP TO Q10)**
Don't know	09	**(SKIP TO Q10)**

HECO is also considering a similar program for air-conditioning.

At your convenience and at no cost to you, they would install a switch on your thermostat that they would control electronically from outside your home. They would probably need to interrupt your air-conditioning for no more than one hour, no more than six times a year.

In return for being able to turn up your thermostat as needed, they would take two dollars off your electric bill every month, whether they interrupted your service or not."

Q9. How likely would you be to participate in a program like this? Would you: **(READ LIST)**

Definitely participate.. 05
Probably... 04
Maybe/maybe not 03
Probably not 02
Definitely not participate 01
Don't know 09

Now I have a few questions for statistical purposes:

Q10. Including yourself, how many people live in your household? **RECORD:** ____________

Q11. How many years have you lived in Hawaii?

Less than 1 year 1
1 to 5 years 2
6 to 20 years 3
Over 20 years, not lifetime 4
Lifetime 5
Don't know/refused 9

Q12. Do you own, or do you rent your home?

Own 1
Rent 2
Neither (live free with family/friends) 3
Refused 9

Q13. With which ethnic group do you identify the most?

Caucasian 1
Chinese 2
Filipino 3
Hawaiian/Part Hawaiian 4
Japanese 5
Mixed (not part Hawn) 6
Black, or African-American 7
Other ________________________________ 8
Refused 9

Q14. What was your age on your last birthday? **RECORD:**_______________years

Q15. Was your total annual household income, before taxes, in 2001......**(READ LIST)**

Under $20,000 1
$20,000 but < $30,000 2
$30,000 but < $50,000 3
$50,000 but < $100,000 4
$100,000 or Over 5
Refused 9

Q16. Gender **(RECORD, DO NOT ASK)**

Male 1

Female 2

In the event my supervisor would like to verify this interview, may I please have your first name?

____

That's all the questions I have. Thank you very much for your time!

Exhibit A

HECO's Residential Direct Load Control Program
Estimated Budgets for 2010 - 2012 ($)

	2010	2011	2012	Total
Customer Incentives				
New Customers	160,200	447,300	688,800	1,296,300
Existing Customers (as of 12/31/09)	1,489,680	1,474,783	1,460,035	4,424,499
Total Customer Incentives	1,649,880	1,922,083	2,148,835	5,720,799
Direct Labor, Tracking & Evaluation [1]				
Administration	134,000	134,000	134,000	402,000
Tracking & Evaluation	111,000	111,000	111,000	333,000
Total Labor, Tracking & Evaluation	245,000	245,000	245,000	735,000
Equipment Purchases + Communication Costs *	35,700	36,900	38,200	110,800
Outside Services				
Load control receiver/switch purchases	652,900	575,000	256,700	1,484,600
Equipment Installation	1,349,800	1,133,200	1,047,100	3,530,100
Equipment Maintenance/Removals	76,590	103,063	132,165	311,818
Total Outside Services	2,079,290	1,811,263	1,435,965	5,326,518
Advertising [1]	424,000	424,000	424,000	1,272,000
Miscellaneous [1]	15,000	15,000	15,000	45,000
TOTAL PROGRAM COSTS	$4,448,870	$4,454,246	$4,307,000	$13,210,116
PROGRAM COSTS LESS BASE EXPENSES [2]	$3,764,870	$3,770,246	$3,623,000	$11,158,116
PROGRAM COSTS FOR NEW INSTALLATIONS ONLY [3]	$ 2,162,900	$ 2,155,500	$ 1,992,600	$ 6,311,000
PROGRAM COSTS FOR MAINTAINING EXISTING INSTALLATIONS	$ 2,285,970	$ 2,298,746	$ 2,314,400	$ 6,899,116

Estimated Incremental Impacts (Gross Generation Level)

		2010	2011	2012	Total
Gross kW [4]	New Installations	5,140	4,148	3,772	13,060
Gross MWh [5]		-	-	-	
Gross kW [4]	Cumulative Impacts	32,548.2	36,723.0	40,495.4	
Gross kW [4, 5]	Acquired Impacts from 2005 to 2009	28,524.6	28,273.0	28,021.4	
Gross kW [4]	Net Impacts (Cumulative - Acquired)	4,023.6	8,450.0	12,474.0	

1 Base labor and base expenses are recovered through base rates and not the IRP Cost Recovery Adjustment per Decision and Order No. 22050 in Docket No. 04-0113 issued 9/27/05.

2 Non-base expenses are recovered through the IRP Cost Recovery Adjustment.

3 Costs includes the purchase and installation of new switches and the incentives for the new installations.

4 Assumes an average interruptible load during the system peak of 0.68 kW for water heaters and 0.88 kW for central and split air conditioners.
Assumes a drop-out rate of 1% for central a/c systems and private home water heaters; 20% for military water heaters

5 There are no energy savings forecasted for the load management programs.
Note: Freeridership is assumed to be 0 for load management programs.

* Equipment purchases/communication consist of base station computer, Yukon software upgrades or equivalent and paging service.

INTEROFFICE CORRESPONDENCE

Hawaiian Electric Company

March 24, 2009

To: Earle Ifuku, Keith Block

From: Ross Sakuda

Subject: HECO Load Management Program Cost Effectiveness Evaluation

In response to your request, the Generation Planning Division has evaluated the cost-effectiveness of the Residential Direct Load Control ("RDLC") and Commercial & Industrial Direct Load Control ("CIDLC") programs to support an application to the Public Utilities Commission ("PUC") for approval of extension of the programs. Calculation of the avoided costs in the cost-effectiveness evaluation was based upon various forecast and planning assumptions, such as:

1. The HECO IRP-4 Resource Plan filed with the PUC in September 2008 in Docket No. 2007-0084, updated with current planning assumptions.
2. The September 2008 Sales and Peak forecast.
3. The preliminary February 2009 Fuel Price Forecast.
4. Information provided by Energy Services in March 2009 to characterize the RDLC and CIDLC programs.

<u>Methodology</u>

The analytical methodology employed here is appropriate to determining the cost-effectiveness of the programs only, and not to calculate unitized avoided cost benefits in terms of $/kW-year or $/kWh. The avoided capital and fixed operation and maintenance ("O&M") costs were calculated by having both the RDLC and CIDLC in, and both the RDLC and CIDLC out of the resource plans. The avoided capacity and fixed O&M for each program were allocated by their respective percentage of the total MW peak impact. The avoided capacity and fixed O&M costs calculation is shown in Attachment 1.

The base resource plan and the effects on the resource timing due to the addition of the RDLC and CIDLC programs are shown in Attachment 2.

The avoided fuel and variable O&M costs attributable to a reduction in spinning reserve requirements are not included in the calculation of the programs benefit/cost ("B/C") ratio because the production simulation model's limited resolution makes it difficult to quantify the fuel benefits and costs.

The BC ratio for the RDLC and CIDLC programs was determined by dividing the net present value (NPV) of the program's capacity deferral benefit (in dollars) by the net present value of the program's cost.

Results
The results are summarized in the following table

	CIDLC	RDLC		LM Total
NPV Benefits (2009$)	$76,583	$74,799		$151,382
NPV Costs (2009$)	$67,227	$45,860		$113,087
B/C Ratio	1.14	1.63		1.34

Conclusions
The programs are cost-effective. Their benefits exceed their costs and their B/C ratios exceed 1.0.

If you have any questions regarding the avoided cost calculations or their application, please contact Robert Uyeunten at 543-7076.

RHS
Attachments

cc w/attach: M. Nakasone
R. Uyeunten
M. Oyadomari
J. Ide

Attachment 1-1
RDLC & CIDLC Avoided Capacity Cost

	Production Revenue Requirements							Energy Requirements			
	with LM			without LM							
Year	Total Production Rev. Req. ($000) (1)	Fixed O&M Rev. Req ($000) (2)	Fuel, Var O&M and Purchased Power ($000) (3)	Total Production Rev. Req. ($000) (4)	Fixed O&M Rev. Req. ($000) (5)	Fuel, Var O&M and Purchased Power ($000) (6)	Avoided Production Costs ($000) (7)	with LM (GWh) (8)	w/o LM (GWh) (9)	Avoided Energy (GWh) (10)	Avoided Energy Costs ($/MWh) (11)
2009	1,017,826	67,906	949,921	1,017,823	67,906	949,918	(3)	7,871	7,871	-	NA
2010	1,228,443	70,274	1,158,169	1,228,443	70,274	1,158,169	(0)	7,852	7,852	-	NA
2011	1,363,791	71,202	1,292,589	1,363,789	71,202	1,292,587	(1)	7,893	7,893	-	NA
2012	1,484,326	78,057	1,406,270	1,484,326	78,057	1,406,270	-	8,001	8,001	-	NA
2013	1,597,269	76,385	1,520,884	1,597,269	76,385	1,520,884	-	8,125	8,125	-	NA
2014	1,763,162	78,066	1,685,096	1,763,420	78,066	1,685,354	235	8,254	8,254	-	NA
2015	1,874,485	79,783	1,794,702	1,875,495	79,783	1,795,712	921	8,385	8,385	0	NA
2016	1,957,605	81,539	1,876,067	1,957,522	81,539	1,875,983	(76)	8,499	8,499	-	NA
2017	2,019,470	83,332	1,936,137	2,018,481	83,332	1,935,149	(901)	8,614	8,614	0	NA
2018	2,144,235	85,166	2,059,069	2,143,964	85,166	2,058,798	(247)	8,731	8,731	-	NA
2019	2,202,271	87,039	2,115,232	2,203,574	88,735	2,114,838	(358)	8,849	8,849	0	NA
2020	2,272,290	88,954	2,183,336	2,279,751	91,505	2,188,246	4,474	8,969	8,969	(0)	NA
2021	2,348,586	90,297	2,258,288	2,361,931	97,722	2,264,209	5,395	9,050	9,050	0	NA
2022	2,452,230	91,661	2,360,569	2,472,102	99,197	2,372,905	11,240	9,132	9,132	(0)	NA
2023	2,498,748	93,045	2,405,703	2,511,920	100,695	2,411,225	5,031	9,215	9,215	0	NA
2024	2,579,845	95,816	2,484,029	2,603,184	101,712	2,501,472	15,893	9,299	9,299	0	NA
2025	2,671,521	97,656	2,573,865	2,679,168	107,823	2,571,345	(2,296)	9,383	9,383	0	NA
2026	2,739,172	98,642	2,640,530	2,747,864	108,912	2,638,952	(1,438)	9,467	9,467	-	NA
2027	2,863,065	104,825	2,758,240	2,864,259	110,012	2,754,247	(3,638)	9,552	9,552	(0)	NA
2028	2,985,147	105,884	2,879,263	2,995,916	116,362	2,879,554	265	9,637	9,637	-	NA

Total (09-28) 34,495
NPV (09$) $13,137

General Notes:
Load forecast Sept 2008 Short Term Fcst (2008-2013)
Aug 2007 Long term growth rate (2014-2028).
HECO 2009 fuel price forecast
LM based on .tfa files from Energy Services dated 3/12/09
EE DSM per Sept 2008 S&P Forecast
PV factor based on after-tax Cost of capital 7.862%
per 7/23/2008 email from FAD

Notes:
1 GAF Utility Costs (fixed & variable O&M, fuel, emissions and purchase power expenses) from PRV System Cost Report for LM AC LM IN R2.sav w/ 20-year LM in 2009
2 Fixed O&M Costs from GAF System Report for LM AC LM IN R2.sav
3 Column (1) minus column (2)
4 GAF Utility Costs from PRV System Cost Report for LM AC LM OUT R2.sav
5 Fixed O&M Costs from GAF System Report for LM AC LM OUT R2.sav.
6 Column (4) minus column (5)
7 Column (6) minus column (3) with the 9.751% revenue tax removed
8 Energy Required from GAF System Report (including losses) LM AC LM IN R2.sav
9 Energy Required from GAF System Report (including losses) LM AC LM OUT R2.sav.
10 Column (9) minus column (8)
11 Column (7) divided by column (10)

The coincident peak reduction in column 24 used in the modeling of the avoided capacity cost is lower than what's stated in the application due to: 1) reporting at the net generation level versus gross generation, 2) annual system peak occurring prior to December when the program expects to have the full number of new switches installed for the year and 3) the model assumes the impact to system peak is shifted by one hour. The programs were still determined to be cost effective with the lower coincident peak reduction.

Attachment 1-2
RDLC & CIDLC Avoided Capacity Cost

	Revenue Requirements												
Year	with LM ($000) (12)	w/o LM ($000) (13)	Net Avoided Revenue Requirements ($000) (14)	CIDLC Revenue Requirements ($000) (15)	RDLC Revenue Requirements ($000) (16)	CIDLC Costs ($000) (17)	RDLC Costs ($000) (18)	Avoided Revenue Requirements ($000) (19)	Avoided Capital and Fixed O&M Costs ($000) (20)	CIDLC Avoided Capital & Fixed O&M ($000) (21)	RDLC Avoided Capital & Fixed O&M ($000) (22)	CIDLC Coincident Peak Reduction (MW) (23)	RDLC Coincident Peak Reduction (MW) (24)
2009	1,038,861	1,038,858	(3)	-	-	-	-	(3)	-	-	-	21.1	22.7
2010	1,265,816	1,255,561	(10,256)	5,550	4,705	5,057	4,287	(0)	-	-	-	25.0	25.7
2011	1,401,589	1,390,892	(10,697)	5,902	4,793	5,378	4,367	(2)	-	-	-	27.0	28 8
2012	1,544,602	1,533,768	(10,835)	6,190	4,644	5,640	4,232	-	-	-	-	28.6	31.7
2013	1,682,980	1,671,354	(11,626)	6,480	5,146	5,904	4,689	-	-	-	-	30.2	34.5
2014	1,850,343	1,838,765	(11,578)	6,769	5,066	6,168	4,616	258	-	-	-	31.8	36.6
2015	1,957,272	1,946,290	(10,982)	7,023	4,970	6,399	4,528	1,010	-	-	-	34 0	37.9
2016	2,037,779	2,024,716	(13,063)	7,859	5,120	7,161	4,665	(84)	-	-	-	35.8	39 1
2017	2,096,530	2,082,231	(14,299)	8,118	5,193	7,396	4,732	(988)	-	-	-	37.4	40.1
2018	2,218,336	2,204,304	(14,032)	8,378	5,382	7,634	4,904	(271)	-	-	-	39.0	41 2
2019	2,273,500	2,288,049	14,549	8,637	5,604	7,869	5,106	28,790	26,590	13,043	13,547	40.6	42 2
2020	2,339,560	2,383,822	44,262	8,827	5,604	8,043	5,106	58,693	49,005	24,270	24,735	41.5	42.3
2021	2,413,314	2,483,332	70,018	8,961	5,604	8,165	5,106	84,583	71,673	35,839	35,834	42.3	42 3
2022	2,514,499	2,591,913	77,414	9,094	5,604	8,286	5,106	92,112	72,689	36,688	36,001	43.1	42 3
2023	2,558,736	2,626,425	67,689	9,228	5,604	8,408	5,106	82,521	70,158	35,733	34,425	43.9	42 3
2024	2,669,594	2,712,680	43,086	9,361	5,604	8,530	5,106	58,051	37,001	19,012	17,988	44.7	42 3
2025	2,786,844	2,803,522	16,678	9,495	5,604	8,651	5,106	31,777	31,250	16,196	15,054	45 5	42 3
2026	2,855,612	2,871,942	16,330	9,629	5,604	8,773	5,106	31,563	30,196	15,781	14,415	46.3	42.3
2027	2,995,168	2,982,761	(12,407)	9,762	5,604	8,895	5,106	2,960	6,335	3,338	2,997	47.1	42.3
2028	3,117,746	3,130,431	12,685	9,896	5,604	9,017	5,106	28,185	25,416	13,498	11,917	47.9	42.3
					Total (09-28)	141,375	92,083		420,313	213,400	206,913		
					NPV (09$)	$67,227	$45,860		$151,382	$76,583	$74,799		

General Notes:

Load forecast Sept 2008 Short Term Fcst (2008-2013)
Aug 2007 Long term growth rate (2014-2028).
HECO 2009 fuel price forecast
LM based on .tfa files from Energy Services dated 3/12/09
EE DSM per Sept 2008 S&P Forecast
PV factor based on after-tax Cost of capital 7.862%
per 7/23/2008 email from FAD

Notes:

12 Utility Cost from PRV System Cost Report for LM AC LM IN R2 sav.
13 Utility Cost from PRV System Cost Report for LM AC LM OUT R2 sav.
14 Columns (13) minus column (12)
15 CIDLC Revenue Requirements
16 RDLC Revenue Requirements
17 Column 15 with the 9.751% revenue tax removed
18 Column 16 with the 9.751% revenue tax removed
19 Column (14) plus Column (15) plus Column (16)
20 Column (19) minus column (7) with the 9.751% revenue tax removed
21 CIDLC avoided capital & fixed O&M (prorated total avoided $ based on peak impacts)
22 RDLC avoided capital & fixed O&M (prorated total avoided $ based on peak impacts)
23 CIDLC coincident peak impacts
24 RDLC coincident peak impacts

Attachment 2
Resource Timing Impacts of the RDLC & CIDLC Programs

Load Management Avoided Cost		
Year	No Future Load Mgmt	With Future Load Mgmt
	LM AC LM OUT r2	LM AC LM IN r2
2009	CIP1 (113 MW)	**Load Management Programs: CIDLC & RDLC** CIP1 (113 MW)
2010	DSG (8 MW)	DSG (8 MW)
2011		
2012	CIP2 (113 MW) MSW (16 MW)	CIP2 (113 MW) MSW (16 MW)
2013	Emergency Reserve W3 (-46 MW)	Emergency Reserve W3 (-46 MW)
2014		
2015		
2016		
2017		
2018		
2019	**Convert CIP1 to STCC (57 MW)**	
2020	**Emergency Reserve W4 (-46 MW)** **DG (50 MW)**	
2021	**DG (50 MW)**	
2022		
2023		
2024		**Convert CIP1 to STCC (57 MW)**
2025	**DG (50 MW)**	**Emergency Reserve W4 (-46 MW)** **DG (50 MW)**
2026		
2027		**DG (50 MW)**
2028	**DG (50 MW)**	

Notes:
(1) Plans are based on September 2008 Short Term S&P Forecast and August 2004 long-term forecast growth rate (2014-2028)
(2) "With Future Load Mgmt" plan includes future and acquired LM, while the "No Future Load Mgmt" plan excludes all LM impacts. Both plans include EE DSM
(3) CIP1 = 1st Simple Cycle CT at Campbell Industrial Park
CIP2 = 2nd Simple Cycle CT at Campbell Industrial Park
DSG = Distributed Standby Generation at the Airport
MSW = Municipal Solid Waste
Convert CIP1 to STCC = Conversion of CIP1 to single train combined cycle
DG = Diesel Generator
(4) All unit additions are assumed to occur on the 1st day of the year
(5) Both plans include the estimated costs for Honua, North Shore Wind, and Sea Solar

RESIDENTIAL DIRECT LOAD CONTROL (RDLC) PROGRAM
Based on RDLC Avoided Capacity Cost Information Provided in Exhibit D

Costs — Program Benefits; Participant Benefits; Utility Program Costs ($); Participant Cost

Year	Program Benefits: RDLC, Avoided Capital & Fixed O&M ($) (1)	Participant Benefits: Customer Bill Savings (2)	Utility Program Costs ($): Total Program Costs (3)	Utility Program Costs ($): Customer Incentives (4)	Utility Program Costs ($): Total Program Costs Less Incentives (5)=(3)-(4)	Utility Program Costs ($): Utility Revenue Decrease (6)	Participant Cost: Direct Customer Costs (7)
2010	$0	$1,500,905	$4,287,000	$1,500,905	$2,786,095	$0.00	$0
2011	$0	$1,861,876	$4,367,000	$1,861,876	$2,505,124	$0.00	$0
2012	$0	$2,115,819	$4,232,000	$2,115,819	$2,116,181	$0.00	$0
2013	$0	$2,401,728	$4,689,000	$2,401,728	$2,287,272	$0.00	$0
2014	$0	$2,591,534	$4,616,000	$2,591,534	$2,024,466	$0.00	$0
2015	$0	$2,718,206	$4,528,000	$2,718,206	$1,809,794	$0.00	$0
2016	$0	$2,811,048	$4,665,000	$2,811,048	$1,853,952	$0.00	$0
2017	$0	$2,899,814	$4,732,000	$2,899,814	$1,832,186	$0.00	$0
2018	$0	$2,986,766	$4,904,000	$2,986,766	$1,917,234	$0.00	$0
2019	$13,547,000	$3,071,256	$5,106,000	$3,071,256	$2,034,744	$0.00	$0
2020	$24,735,000	$3,071,256	$5,106,000	$3,071,256	$2,034,744	$0.00	$0
2021	$35,834,000	$3,071,256	$5,106,000	$3,071,256	$2,034,744	$0.00	$0
2022	$36,001,000	$3,071,256	$5,106,000	$3,071,256	$2,034,744	$0.00	$0
2023	$34,425,000	$3,071,256	$5,106,000	$3,071,256	$2,034,744	$0.00	$0
2024	$17,986,000	$3,071,256	$5,106,000	$3,071,256	$2,034,744	$0.00	$0
2025	$15,054,000	$3,071,256	$5,106,000	$3,071,256	$2,034,744	$0.00	$0
2026	$14,415,000	$3,071,256	$5,106,000	$3,071,256	$2,034,744	$0.00	$0
2027	$2,997,000	$3,071,256	$5,106,000	$3,071,256	$2,034,744	$0.00	$0
2028	$11,917,000	$3,071,256	$5,106,000	$3,071,256	$2,034,744	$0.00	$0

Cost Tests

Present Value of Program Benefits					Present Value of Program Costs				Cost Benefit Ratios			
Present Value ("PV") Factor (8)	PV of Utility Program Benefits (UC) (9) = PV of (1) @ (8)	PV of Utility Program Benefits (TRC) (10) = PV of (1) @ (8)	PV of Participant Benefits (P) (11) = PV of (2) @ (8)	PV of Utility Program Benefits (RIM) (12) = PV of (1) @ (8)	PV of Utility Program Costs (UC) (13) = PV of (3) @ (8)	PV of Program Costs Less Incentive Plus Customer Costs (TRC) (14) = PV of (5+7) @ (8)	PV of Participant Costs (P) (15) = PV of (7) @ (8)	PV of Program Costs plus lost sales (RIM) (16) = PV of (3+6) @ (8)	Utility Cost/Benefit Test (17) = (9) / (13)	Total Resource Cost/Benefit Test (18) = (10) / (14)	Participant Cost/Benefit Test (19) = (11) / (15)	Rate Impact Measure Cost/Benefit Test (20) = (12) / (16)
0.07862	$74,799,436	$74,799,436	$25,196,528	$74,799,436	$45,858,926	$20,662,398	$0	$45,858,926	1.63	3.62	Infinite	1.63

PUC-IR-165

Please provide a full and detailed explanation of all IRP activities conducted by HECO in both 2008 and 2009 to date. Please quantify the costs of these activities, breaking such costs down into the expense of salaried employees and other expenses, such as consultants, and describe any such other expenses.

HECO Response:

The following table lists the four major categories of costs related to the IRP/CESP for 2008 and 2009 up to the end of August. The September 2009 actual costs are not currently available.

	2008 Actual $ dollars	Jan-Aug 2009 Actual $ dollars
Labor & Overhead	$705,849	$359,674
Materials & Supplies	1,698	790
Outside Services (consultants, advertising)	220,017	70,586
Other (travel, information technology)	60,217	65,801
Total	**$987,781**	**$496,851**

Labor

HECO filed its fourth integrated resource plan ("IRP-4") on September 30, 2008 in Docket No. 2007-0084. The 2008 actual costs included IRP activities that were labor intensive because the majority of the analytical planning work was being conducted during the April-August 2008 timeframe. Other activities included, but are not limited to, conducting advisory group meetings, public meetings, and preparing the report for the filing.

On November 26, 2008, the Commission closed Docket No. 2007-0084 and stated "As the commission is closing this docket to allow for resources to be diverted to development of a CESP [F]ramework, the [C]ommission directs HECO to suspend all activities pursuant to the IRP Framework." HECO complied with the Commission's order and began developing the proposed CESP Framework at the end of 2008.

From January to April 2009, HECO developed a draft strawman proposal of the CESP Framework and met with the Consumer Advocate, Kauai Island Utility Cooperative ("KIUC"), and Life of the Land to discuss the proposal. HECO also conducted a public meeting on April 7, 2009 to present the draft strawman to obtain input from the public. On April 28, 2009, HECO filed the proposed CESP Framework, in coordination with the Consumer Advocate and KIUC, and asked the Commission to open a new investigatory docket to review and establish the CESP Framework. On May 14, 2009, the Commission opened Docket No. 2009-0108, *Instituting a Proceeding to Investigate Proposed Amendments to the Framework for Integrated Resource Planning*. HECO held technical sessions with the parties in the docket on August 11 and September 15, 2009. The Commission recently approved the Stipulated Procedural Order ("SPO") on September 23, 2009. HECO prepared and filed its Preliminary Statement of Position on October 2, 2009 in accordance with the SPO and are continuing discussions with the other parties.

<u>Materials & Supplies</u>

The materials and supplies costs in 2008 were to support advisory group meetings, public meetings, and the report filing for the IRP-4 process. The materials and supplies costs for January through August 2009 were to support the public meeting, technical sessions, and filings related to the proposed CESP Framework.

<u>Outside Services</u>

Outside services for 2008 included the utilization of consultants to support HECO in IRP-4 activities such as developing energy and demand forecasts, developing demand-side management programs, performing the integration analyses to result in resource plans, providing legal support, and advertising and conducting public meetings.

Outside services from January to August 2009 has been minimal in accordance with the Commission's order "to suspend all activities pursuant to the IRP Framework." The consultant studies that have been conducted included updating economic forecasts and research and development studies that were already contracted for and in progress.

<u>Other</u>

Other costs related to IRP/CESP in 2008 included travel expenses to advisory group and public meetings, maintenance of information technology software and hardware, and mainland travel to attend conferences related to utility planning and climate change policy initiatives.

For January to August 2009, other costs include primarily an allocation of costs for maintenance of Company software and hardware by the Information Technology Department, and costs for mainland travel to attend conferences related to utility planning and renewable energy initiatives.

PUC-IR-166

Please provide a full and detailed explanation of all IRP activities anticipated through the remainder of 2009 and during 2010. Please quantify the costs of these activities, breaking such costs down into the expense of salaried employees and other expenses and describe any such other expenses.

HECO Response:

The following table lists the four major categories of costs related to IRP/CESP for the period 2008 to 2010, with 2009 detailed with January to August recorded and September to December estimated.[1] The estimates shown below for the remainder of 2009 should not be construed as an exact estimate of what may actually be spent through the rest of the year.

	2008 Recorded	2009 Jan-Aug Recorded	2009 Sep-Dec Estimated	2009 Estimated	2010 Budget Estimate
Labor & Overhead	$705,849	$359,674	$223,567	$583,241	$806,400
Materials & Supplies	1,689	790	817	1,607	1,166
Outside Services (consultants, advertising)	220,017	70,586	140,000	210,586	756,651
Other (travel, information technology)	60,217	65,801	29,981	95,782	69,861
Total	**$987,781**	**$496,851**	**$394,365**	**$891,216**	**$1,634,078**

Labor

As explained in response to PUC-IR-165, HECO held technical sessions with the parties in the docket on August 11 and September 15, 2009. The Commission recently approved the Stipulated Procedural Order ("SPO") on September 23, 2009. HECO prepared and filed its Preliminary Statement of Position on October 2, 2009 in accordance with the SPO and are continuing discussions with the other parties. There is another technical session being planned for either October 21 or October 22, 2009. In accordance with the SPO schedule approved by

[1] Since PUC-IR-165 requests the cost information for 2008 and 2009 YTD recorded, these figures are presented in the table to facilitate review and for ease of reference.

the Commission, activities to be carried out for the remainder of 2009 include providing information requests to the parties by November 10, responding to comments provided by the Commission's consultant, the National Regulatory Research Institute ("NRRI") by November 20, responding to any Information Requests received by the parties by November 25, 2009, and filing a Final Statement of Position by December 21, 2009.

The SPO schedule extends out to 2010 with a prehearing conference scheduled for the week of January 19, 2010, panel hearing the week of January 25, 2010, opening briefs three weeks after the filing of transcripts, and reply briefs two weeks after the filing of transcripts.

Activities for the rest of 2010, beyond that listed in the SPO schedule, is dependent on when the Commission issues a decision and order in Docket No. 2009-0108 establishing a new planning framework and what the requirements for the new planning process will be. For budgeting purposes, HECO has made estimations based on the assumption that a new planning process would begin in mid-2010 and that the planning process would be based on what HECO is proposing as the CESP Framework. Although uncertainty exists as to what the detailed tasks in the CESP process may involve, the CESP process envisions additional planning requirements such as the development of locational value maps and renewable energy zones. As explained in response to PUC-IR-125, as a conservative estimate, the labor for 2010 was based on utilizing the same Company resources that were involved with the past IRP process, expanded to include the Distribution Planning and Renewable Energy Planning Divisions.

Materials & Supplies

The materials and supplies costs for January through August 2009 were to support the public meeting, technical sessions, and filings related to the proposed CESP Framework.

The materials and supplies costs budgeted for 2010 include estimates for supporting the filings related to the proposed CESP Framework, and for public and advisory committee meetings assuming that the new planning process begins in mid-2010.

Outside Services

Outside services for the remainder of 2009 is estimated to be approximately $140,000 which includes $50,000 for consultant studies that are already contracted for and in progress, related to renewable energy initiatives such as solar monitoring data collection at the Kahe power plant. The data collected in this study will help to determine the solar options available on the lands within 100 acres of the Kahe power plant. The collection of data for this study will continue until August 2010. The estimate also includes approximately $10,000 for legal services in support of the development of the CESP Framework, and approximately $80,000 for the licensing fee for the Strategist software, which the Energy Services Department uses to develop load profile inputs for energy efficiency and demand response program impacts, a conditional demand analysis that will convert whole house usage and household appliance stock into estimates of appliance usage, and a demand response potential study that will provide the basis for demand response program design and measure program achievement.

Again, for the 2010 budget, it was assumed that the new CESP planning process would begin in the middle of the year. Since the planning process is assumed to be new and there is uncertainty as to what the detailed tasks in the CESP process may involve, the estimated budget included outside consultant services for conducting a full-scale supply-side resource analysis, support for developing energy and demand forecasts, technical planning and modeling analyses, and research and development studies.

As in the past IRP cycles, the start of the CESP planning cycle would entail developing the assumptions to be used in the analyses, such as demand and energy forecasts, fuel price forecasts, demand-side management forecasts, distributed generation forecasts, and data for supply-side resource options. Development of the assumptions is the first phase in the planning process and is in general, the most time-consuming and meticulous. Since the responsibility of energy efficiency demand-side management programs have been transferred to a third-party Public Benefits Fund Administrator, the proposed CESP Framework identifies forecasts for energy efficiency programs to be the responsibility of the third-party Public Benefits Fund Administrator. The 2010 budget estimate for demand-side management forecasts reflects this change in responsibility from prior IRPs but does include the development of a market potential study which provides market information than can be used for both the third-party administor's energy efficiency programs and HECO's demand response load management programs.

The second phase of the planning process is conducting the technical analysis which uses the assumptions that were developed and is expected to be labor intensive. Since there is uncertainty in the details of what the technical analyses will entail, HECO is estimating outside consultants to help support Company resources in this effort. The technical analysis would provide various plans/scenarios that would be used for the last phase of the planning process.

Since the CESP Framework is still being developed, there is uncertainty in what supply-side resources[2] will be analyzed in the CESP process. It is unknown whether there are existing supply-side resource data readily available or if new data will have to be developed. Data for supply-side resources are needed in order to accurately characterize supply resource candidates

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[2] Supply-side resource options are generating units, which can be fossil-fueled or biofueled resources using conventional technology or renewable energy resources. Supply-side resources include both central and distributed generation options.

for capacity planning, energy planning, operational modeling, economic evaluation, and other resource integration and plan development and analysis. Data associated with each supply-side resource option include, but is not limited to, unit rating, ambient conditions, service life, normal top load capacity, capacity factor, typical hourly generation profile (if applicable), heat rate (if applicable), capital cost, expenditure pattern, estimated installation schedule, fixed operations and maintenance costs, variable operations and maintenance costs, emission rates (nitrogen oxides, sulfur oxides, carbon dioxide, carbon monoxide, volatile organic compounds, and particulate matter), waste streams (solid waste, water discharge, water discharge temperature, and thermal discharge amount), resource requirements (fuel, service and plant water, cooling water makeup, and supply water temperature), general site and technology characteristics (fuel delivery, fuel storage on-site, water supply source, cycle cooling, solid waste disposal, and land space required), startup parameters, availability (maintenance patterns, maintenance outage requirements, forced outage rate), and staffing requirements. These generation unit descriptions are referred to as unit information forms ("UIFs") that is used in the modeling for the development of the resource plans.

A full-scale supply-side resource analysis would begin with a comprehensive list of candidate resource options which would be evaluated through two screening processes. The initial screening process used criteria such as unit size, technology status, resource requirements, and capital costs. Those resource options that did not meet the specified criteria would be dropped from further evaluation in the current planning process but would be continually monitored for future development. During the final screening, the supply-side resources were then categorized as either commercial or developing. Commercial resources considered viable in the immediate to five-year time frame are those that satisfy five criteria: (1) vendor availability,

(2) proven technology, (3) utility scale, (4) well-established capital and operating costs, and (5) resource availability. Developing resources considered viable in the 6- to 20-year time frame are those that satisfy four criteria: (1) sole or multiple vendors, (2) emerging technologies, (3) potential for competitive capital and operating costs, and (4) resource availability. The resources that were considered commercial were developed into UIFs used in the technical analysis for developing resource plans.

A full-scale supply-side resource analysis was performed as part of the IRP-1 process. The most recently filed IRP-4 used supply-side resources from the IRP-3 process, the IRP-3 process built upon supply-side resources from the IRP-2 process, which built upon data and information from the IRP-1 process in the development of supply-side resources. In each build up, supply-side resources data were reviewed and updated using current cost information available. It is likely that new supply-side resources, versus what were used in the past IRP processes, will have to be explored and developed due to: (1) technology and market changes have resulted in rapidly changing costs and other key parameters for generation options, (2) the CESP process will likely include in its integration phase analysis that considers new generation technologies, new fuel options, new re-powering options, and (3) availability of a greater variety of generating unit sizes (central-station and distributed generation). An example is the development of data for modern, wind turbine generators that employ state-of-the-art power electronics that improve its performance characteristics compared with less sophisticated and previous generation technology turbines. Retirement of existing generating units or placement on emergency standby may also be considerations in the proposed CESP process which could warrant the need for additional repowering supply-side resource data that is not in existence. It is prudent to assume that the first CESP process will entail new supply-side resources that will require a full-scale study. Since the details of what the study would include is still unknown, a rough estimate for an outside consultant to perform this work is included in the 2010 budget and would change dependent on the outcome of the proposed CESP Framework docket.

Other

Other costs for September to December of 2009 include maintenance of information technology software and hardware, and mainland travel to attend a conference related to utility long range planning.

For 2010, the budget estimate included maintenance of information technology software and hardware, and mainland travel to attend conferences related to utility planning or policy-initiatives.

PUC-IR-167

On page 4 of HECO-S-1103, HECO stated that it must periodically update the Ellipse 6 software, with the last upgrade taking place in 2002-2003. Did HECO consider normalizing the costs of Ellipse 6 software over the expected life of the software? Please describe why such normalization would or would not be appropriate.

<u>HECO Response:</u>

HECO did not normalize the costs for the Ellipse 6 software estimated for 2009 because HECO would continue to incur costs for the Ellipse 6 upgrade in 2010, and HECO will incur other costs related to Ellipse after 2009.

The basis for HECO's position needs to be reviewed in light of the way costs related to software upgrades, specifically for Ellipse, have been included in rates. (Ellipse, formerly referred to as the Mincom Information Management System, or MIMS, was implemented effective January 1, 1999. HECO's rate case before the implementation was in 1995, and the next rate case was a 2005 test year.)

In HECO's 2005 test year rate case, Docket No. 04-0113, HECO proposed to include in its test year estimate a normalization adjustment amount for the periodic upgrade of Ellipse. HECO had completed a software upgrade in the 2002-2003 time period. Normalized costs for Ellipse had not been included in rates prior to the 2005 rate case. In the 2005 rate case, HECO estimated the cost of the next upgrade based on the out of pocket costs for the 2002-2003 upgrade and escalated the cost by 2% to the estimated time of the next upgrade. The estimated cost was divided by four (the estimated 4-year life cycle between upgrades).

The Consumer Advocate in the 2005 rate case proceeding objected to the inclusion of costs for periodic upgrades of Ellipse in the 2005 test year estimates, since the next upgrade was expected to occur in 2007, two years after the 2005 test year. The Consumer Advocate rationalized that it was not appropriate to include a normalized cost that would not occur in the test year. In the interest of compromise and to settle the issues in the case, the parties agreed to exclude HECO's proposed normalization adjustment for Ellipse upgrade costs in the 2005 test year rate case.

In HECO's 2007 test year rate case, Docket No. 2006-0387, HECO's revised test year estimate included the non-labor costs of $854,000 for Ellipse migration to Unix platform project that would be incurred in 2007. The Ellipse migration project would continue into 2008 and the non-labor costs estimated for 2008 was $320,000. The Consumer Advocate in the proceeding, proposed to normalize only the costs for 2007 ($854,000) over three years. For purposes of settlement, the Company agreed to the Consumer Advocate's proposal of including only one-third of the cost estimated to be incurred in the test year in determining the Company's revenue requirements.[1] Thus, HECO did not have an opportunity to recover the full cost of the Ellipse 6 migration to Unix platform as the costs that were incurred in 2008 were not considered. Further, since HECO's next rate case is this 2009 test year rate case in Docket No. 2008-0083, which is less than 3 years from the 2007 rate case, the remaining amounts have not been reflected in rates.[2]

HECO chose not to normalize the costs estimated for 2009 for the Ellipse 6 software project for ratemaking purposes because of the previous method for determining test year expense estimates related to costs for the Ellipse system. The Company is required to implement periodic software upgrades every 4 to 5 years. However, if the costs are not incurred in the test year, the Consumer Advocate opposes including a normalized level of costs in the test year for

[1] The amount included in revenue requirements also considered the amounts that would be transferred to capital as part of the A&G transferred calculation.
[2] One-third of the costs of the Ellipse Migration to Unix project was not included in the 2009 test year expenses, even if the 2007 test year expenses were based on a 3-year normalization.

something that occurs periodically. In addition, the Consumer Advocate only considers the cost that would be incurred in the test year, even if the costs for the project extend beyond a year. Thus, for the Ellipse 6 software costs, the costs that would be incurred in the test year are included in the test year estimates. HECO is just seeking a mechanism to have the ability to recover the prudent and necessary software costs for a system that is utilized in providing reliable service to customers.

HECO would not oppose normalizing the cost of a software upgrade if all of the costs are considered and the amortization period is based on the time period between rate cases. For the Ellipse 6 project, it should include the costs for 2009 as well as 2010, in determining the normalization amount. Further, if a rate case occurs between upgrades, the normalized cost of an upgrade should be considered in the test year expenses, even if the actual costs would not be incurred in the test year. In that way, the Company will have a reasonable opportunity to recover all the prudent costs of necessary software upgrades, not just the costs that happen to occur during a test year.

Consider a cost that is incurred every two years. If the cost is incurred in the test year, and is normalized over a two-year period, the appropriate amount of cost is recovered. If the cost is incurred in the year before or the year after the test year, and zero cost is included in the test year, the company is foreclosed from any cost recovery. If normalization is employed, it cannot be employed only to recover costs from the test year – it must be employed to allow recovery of a "normalized" level of costs over the period rates are in effect.

HECO completed the upgrade planning study to identify the enhancements Ellipse 6 offered, conducted an Ellipse lifecycle review and confirmed Mincom's support timeline for Ellipse 6 in June 2009. While the project team recommended proceeding with the upgrade to

Ellipse 6, the Company made a decision not to undertake the Ellipse 6 upgrade projects at this time. HECO incurred approximately $212,000 for non-labor costs related to the upgrade planning study. In addition, as a result of not upgrading to Ellipse 6, we will need to incur consulting costs from Mincom (estimated at $107,800) to address some customization issues with the current version of Ellipse primarily in the payroll register and time and attendance tracking. These issues would have been addressed with the Ellipse 6 upgrade.

Thus, while HECO will not incur the full $1,145,000 for consultant fees in the test year for the Ellipse upgrade implementation, HECO already incurred $212,000 for the planning study and will be incurring $107,800 to continue to operate the current version of Ellipse. Note that included in the test year estimates in Account No. 921, is $362,000 for software costs for Ellipse 6.

PUC-IR-169

Please provide a full and detailed narrative explanation of why all cost increases in the proposed Settlement Agreement were on a per-kWh basis rather than on a percentage basis for all revenues.

HECO Response:

In the Settlement Agreement, HECO, the Division of Consumer Advocacy, and the Department of Defense proposed to implement the interim rate increase on a cents per kWh basis (Settlement Agreement, Exhibit 1, page 85). HECO had made this proposal because of the simplicity of the rate design, ease and efficiency of rate administration, and the clarity provided to customer bills (HECO T-22, pages 56-57). However, to address the Commission's concerns regarding an interim rate increase assigned to customer classes on a per-kWh basis, (Interim Decision and Order, dated July 2, 2009, pages 15-16), the Company proposed to implement the interim rate increase as percentage increases assigned to customer classes as was done in the implementation of interim rate increases in the most recent rate cases (HECO Revised Schedules Resulting from Interim Decision and Order, dated July 8, 2009, Exhibit 2 and Exhibit 2A, page 1). The Commission approved this proposal and HECO implemented the 2009 test year interim rate increase on August 3, 2009.

In the Settlement Agreement, rate increases based on any final increase in electric revenues to the proposed rate classes were proposed to be assigned to customer charges, energy charges, and demand charges at specified amounts (see Settlement Agreement, HECO T-22, Attachment 2 and also HECO's response to PUC-IR-170).

PUC-IR-170

Please describe all reasons why the rate increase resulting from this rate case should or should not be allocated to both the fixed and per-kWh components of rates.

HECO Response:

HECO's proposed rate design in direct testimony (HECO T-22, pages 26-50) and the proposed rate design in the Settlement Agreement (Stipulated Settlement Letter, May 15, 2009, HECO T-22, Attachment 2) both include proposed increases assigned to customer charges, energy charges, and demand charges. Proposed increases to customer charges and to demand charges are intended to more closely align them with customer-related costs and demand-related costs, respectively. However, for all proposed rate schedules, the proposed energy charges do recover customer-related costs that are not recovered by the proposed customer charges and demand-related costs that are not recovered by the proposed demand charges.

PUC-IR-173

Did HECO hire any third parties to assist it in the March 2, 2009 and April 13, 2009 reorganizations referenced on pages 4 through 7 of HECO ST-15? If so, please describe the role of such third parties and the nature of any reports they produced.

<u>HECO Responses:</u>

No. Hawaiian Electric did not hire any third parties to assist in the March 2, 2009 and April 13, 2009 reorganizations.

PUC-IR-175

Please confirm or deny that the following image is from page 300 of HECO's 2008 FERC Financial Reporting Form No.1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report, which HECO filed on April 15, 2009. The commission obtained this image from a PDF from FERC's website.

Hawaiian Electric Company, Inc. | (1) [illegible] (2) A Resubmission | [illegible] | Year/Period of Report End of [illegible]

ELECTRIC OPERATING REVENUES (Account 400)

[illegible]

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	[illegible]	[illegible]
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	[illegible]	[illegible]
5	Large (or Ind.) (See Instr. 4)	[illegible]	[illegible]
6	(444) Public Street and Highway Lighting	[illegible]	[illegible]
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	[illegible]	[illegible]
11	(447) Sales for Resale		
12	TOTAL Sales of Electricity	[illegible]	[illegible]
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	[illegible]	[illegible]
15	Other Operating Revenues		
16	(450) Forfeited Discounts	[illegible]	[illegible]
17	(451) Miscellaneous Service Revenues	[illegible]	[illegible]
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	[illegible]	[illegible]
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	[illegible]	[illegible]
22	(456.1) Revenues from Transmission of Electricity of Others		
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	[illegible]	[illegible]
27	TOTAL Electric Operating Revenues	[illegible]	[illegible]

FERC FORM NO. 1/3-Q (REV. 12-05) Page 300

HECO Response:

HECO confirms that the image is consistent with page 300 of HECO's 2008 FERC Financial Reporting Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report.

PUC-IR-176

Please confirm or deny that the following image is from page 300 of HECO's revised 2007 FERC Financial Reporting Form No.1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report, which HECO filed on May 8, 2008. The commission obtained this image from a PDF from FERC's website.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	[illegible]	[illegible]
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	[illegible]	[illegible]
5	Large (or Ind.) (See Instr. 4)	[illegible]	[illegible]
6	(444) Public Street and Highway Lighting	[illegible]	[illegible]
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	[illegible]	[illegible]
11	(447) Sales for Resale		
12	TOTAL Sales of Electricity	[illegible]	[illegible]
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	[illegible]	[illegible]
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,392,172	[illegible]
17	(451) Miscellaneous Service Revenues	782,683	[illegible]
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	[illegible]	[illegible]
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	[illegible]	[illegible]
22	(456.1) Revenues from Transmission of Electricity of Others		
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	[illegible]	[illegible]
27	TOTAL Electric Operating Revenues	[illegible]	[illegible]

HECO Response:

HECO confirms that the image is consistent with page 300 of HECO's revised 2007 FERC Financial Reporting Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report.

PUC-IR-183

Please describe any recent HECO policies to reduce vehicle maintenance/painting expenses. With respect to any such policy, provide the following:

a. A full and detailed narrative description of the policy

b. Any documents detailing the policy

c. Expected savings from the policy in both 2009 and 2010

d. Whether the policy is expected to continue going forward or operate for only a short time and why. If it is only expected to operate for a short duration, specify the termination date.

<u>HECO Response:</u>

a. The policy, "HECO Vehicle - Painting and Logos" policy was revised in August, 2009. In accordance with this policy from August 2009 going forward HECO will be purchasing its vehicles painted white and applying reflective decals in lieu of its traditional tri-colored paint scheme of yellow, white and blue. Vehicles that have the tri-colored paint scheme of yellow, white and blue will remain the same and will not be repainted in accordance with the August 2009 policy.

b. See Attachment 1 of this response.

c. The expected capital savings in 2009 is $50,000.

   The expected capital savings in 2010 is $90,000.

   These savings are based on the forecasted capital purchase of 1 heavy truck, 1 medium truck, and 15 light trucks for the remainder of 2009 and 7 heavy trucks, 3 medium trucks, and 15 light trucks in 2010 to which the new paint scheme will be applied. The capital cost savings varies depending on the type of vehicle being painted and the number purchased each year. These are capital cost savings because the tri-color painting costs were included in the price of the vehicles since they were painted by the dealer. The savings generally falls within the range of $2,800 to $5,600 per vehicle.

d. HECO will follow August 2009 policy going forward.

August 28, 2009

Company Policy

<u>HECO Vehicles – Painting and Logos</u>

All HECO vehicles will be painted white and detailed with reflective striping and decals with the following exceptions:

Exceptions:

1. All vehicles assigned as take home vehicles shall not have company logos or markings.
2. All loaner or pool vehicles that may be used as take home vehicles shall not have company logos or markings.
3. All other passenger vehicles will be marked with a HECO logo decal unless the Energy Delivery VP gives written approval to leave the car unmarked.

All other stickers/decals or articles (ornaments) are not allowed on company vehicles unless authorized by the Energy Delivery Vice President.

Mark Shimabukuro
Acting Support Services Manager

Harold Kageura
Energy Delivery Vice President

Rev.1 – August 28, 2009
Original Edition – July 2, 1985